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VOC (Volatile Organic Compound) Fugitive Emissions in Petroleum Refining Industry Background Information for Proposed Standards

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15. SUPPLEMENTARY NOTES This report discusses the regulatory alternatives considered during development of the proposed new source performance standards and the environmental and economic impacts associated with each regulatory alternative.

16. ABSTRACT

Standards of performance for the control of volatile organic compound (VOC) fugitive emissions from the petroleum refining industry are being proposed under Section 111 of the Clean Air Act. These standards would apply to fugitive emission sources of VOC within new, modified, and reconstructed petroleum refinery compressors and process units. This document contains background information and environmental and economic impact assessments of the regulatory alternatives considered in developing the proposed standards.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
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Emission Standards and Engineering Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air, Noise, and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

November 1982

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ENVIRONMENTAL PROTECTION AGENCY

Background Information
and Draft
Environmental Impact Statement
for VOC Fugitive Emissions in Petroleum Refining Industry

Prepared by:

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1. The proposed standards of performance would limit emissions of volatile organic compounds from new, modified, and reconstructed compressors and process units in the petroleum refining industry. Section 111 of the Clean Air Act (42 U.S.C. 7411), as amended, directs the Administrator to establish standards of performance for any category of new stationary source of air pollution that "...causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."

2. Copies of this document have been sent to the following: Federal Departments of Labor, Health and Human Services, Defense, Transportation, Agriculture, Commerce, Interior, and Energy; the National Science Foundation; and Council on Environmental Quality; members of the State and Territorial Air Pollution Program Administraors; the Association of Local Air Pollution Control Officials; EPA Regional Administrators; and to other interested parties.

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TABLE OF CONTENTS

Title | Page

LIST OF TABLES. vii
LIST OF FIGURES xiii
METRIC CONVERSION TABLE xiv
1.0 SUMMARY 1-1
  1.1 Regulatory Alternatives. 1-1
  1.2 Environmental Impact 1-2
  1.3 Economic Impact. 1-3
2.0 INTRODUCTION. 2-1
  2.1 Background and Authority for Standards 2-1
  2.2 Selection of Categories of Stationary Sources. . . 2-4
  2.3 Procedure for Development of Standards of Performance. 2-6
  2.4 Consideration of Costs 2-8
  2.5 Consideration of Environmental Impacts 2-9
  2.6 Impact on Existing Sources 2-10
  2.7 Review of Standards of Performance 2-11
3.0 DESCRIPTION OF PETROLEUM REFINERY FUGITIVE VOC EMISSION SOURCES. 3-1
  3.1 Introduction and General Industry Information. . . 3-1
  3.2 Fugitive Emission Definition and Potential Source Description 3-3
  3.3 Baseline Control 3-14
  3.4 References 3-17
4.0 EMISSION CONTROL TECHNIQUES 4-1
  4.1 Introduction 4-1
  4.2 Leak Detection and Repair Programs 4-1
  4.3 Preventive Programs. 4-12
  4.4 References 4-27
5.0 MODIFICATION AND RECONSTRUCTION 5-1
  5.1 General Discussion of Modification and Reconstruction Provisions. 5-1
  5.2 Applicability of Modification and Reconstruction Provisions to Refinery VOC Fugitive Emission Sources 5-3

TABLE OF CONTENTS (concluded)

Title Page

5.3 References 5-5

6.0 MODEL UNITS AND REGULATORY ALTERNATIVES 6-1

6.1 Introduction 6-1

6.2 Model Units. 6-1

6.3 Regulatory Alternatives. 6-4

6.4 References 6-8

7.0 ENVIRONMENTAL IMPACTS 7-1

7.1 Introduction 7-1

7.2 VOC Emissions Impact 7-1

7.3 Water Quality Impact 7-9

7.4 Solid Waste Impact 7-9

7.5 Energy Impacts 7-10

7.6 Other Environmental Concerns 7-10

7.7 References 7-13

8.0 COST ANALYSIS 8-1

8.1 Cost Analysis of Regulatory Alternatives 8-1

8.2 Other Cost Considerations. 8-27

8.3 References 8-39

9.0 ECONOMIC IMPACT 9-1

9.1 Industry Characterization. 9-1

9.2 Economic Impact Analysis 9-25

9.3 Socioeconomic and Inflationary Impacts 9-40

9.4 References 9-47

APPENDIX A A-1

APPENDIX B B-1

APPENDIX C C-1

APPENDIX D D-1

APPENDIX E E-1

APPENDIX F F-1

LIST OF TABLES

Table — Page

1-1 Environmental and Economic Impacts of Regulatory Alternatives 1-4

3-1 Uncontrolled Fugitive Emission Factors in the Petroleum Refining Industry. 3-15

3-2 Estimated Fugitive VOC Emissions from a Hypothetical 10-Unit Petroleum Refinery 3-16

4-1 Percentage of Sources Predicted to be Leaking in an Individual Component Survey. 4-3

4-2 Percent of Total Mass Emissions Affected at Various Leak Definitions 4-8

4-3 Emission Correction Factors for Various Inspection Intervals, Allowable Repair Times, and Leak Definitions. 4-13

6-1 Model Unit Component Counts. 6-3

6-2 Fugitive VOC Regulatory Alternative Control Specifications 6-5

7-1 Controlled VOC Emission Factors for Various Inspection Intervals 7-3

7-2 VOC Emissions for Regulatory Alternatives. 7-4

7-3 Annual Model Unit Emissions and Average Percent Emission Reduction from Regulatory Alternative I 7-7

7-4 Projected VOC Fugitive Emissions from Affected Model Units for Regulatory Alternatives for 1982-1986. 7-8

7-5 Projected Energy Impacts for Regulatory Alternatives for 1982-1986 7-10

8-1 Installed Capital Cost Data. 8-2

8-2 Installed Capital Cost Estimates for New Model Units. 8-5

8-3 Monitoring and Maintenance Labor-Hour Requirements . . . 8-9

8-4 Leak Detection and Repair Costs. 8-10

LIST OF TABLES (continued)

Table Page

8-5 Derivation of Annualized Labor, Administrative, Maintenance, and Capital Costs 8-12

8-6 Labor-Hour Requirements for Initial Leak Repair. . . . 8-13

8-7 Initial Leak Repair Costs. 8-14

8-8 Recovery Credits 8-16

8-9 Annualized Control Cost Estimates for New Facilities for Model Unit A 8-17

8-10 Annualized Control Cost Estimates for New Facilities for Model Unit B 8-18

8-11 Annualized Control Cost Estimates for New Facilities for Model Unit C 8-19

8-12 Cost-Effectiveness for Model Units for New Facilities 8-20

8-13 Installed Capital Cost Estimates for Modified/ Reconstructed Facilities 8-22

8-14 Annualized Control Cost Estimates for Modified/ Reconstructed Facilities for Model Unit A. 8-23

8-15 Annualized Control Cost Estimates for Modified/ Reconstructed Facilities for Model Unit B. 8-24

8-16 Annualized Control Cost Estimates for Modified/ Reconstructed Facilities for Model Unit C. 8-25

8-17 Fifth-Year Nationwide Costs for the Petroleum Refining Industry Above Regulatory Alternative I Costs 8-26

8-18 Fifth-Year Nationwide Costs for the Petroleum Refining Industry Above Baseline Costs 8-28

8-19 Statutes That May Be Applicable to the Petroleum Refining Industry. 8-29

8-20 Summary of Fifth-Year Annualized Costs by Standard . . 8-31

9-1 Total and Average Crude Distillation Capacity by Year, United States Refineries, 1970-1980 9-2

LIST OF TABLES (continued)

Table Page

9-2 Percent Volume Yields of Petroleum Products by Year, United States Refineries, 1971-1978. 9-4

9-3 Production of Petroleum Products by Year, United States Refineries, 1969-1978 9-5

9-4 Number and Capacity of Refineries Owned and Operated by Major Companies, United States Refineries, 1980 9-6

9-5 Employment in Petroleum and Natural Gas Extraction and Petroleum Refining by Year, United States, 1969-1978. 9-8

9-6 Average Hourly Earnings of Selected Industries by Year, United States, 1969-1978. 9-10

9-7 Estimated Gasoline Pool Composition by Refinery Stream, United States Refineries, 1981 9-11

9-8 Refinery Capacity, Capacity Utilization, and Refined Product Demand Projections Under Three World Oil Price Scenarios, United States Refineries, 1978-1985-1990-1995. 9-14

9-9 Price Elasticity Estimates for Major Refinery Products by Demand Sector, United States, 1985 9-16

9-10 Crude Oil Production and Consumption By Year, United States, 1970-1979 9-18

9-11 Oil Exploration and Discoveries by Year, United States, 1970-1979. 9-19

9-12 Average Prices: Gasoline, Distillate Fuel Oil, and Residual Fuel Oil by Year, United States, 1968-1979. 9-20

9-13 Price Projections for Selected Petroleum Products by Year, United States, 1978-1985-1990-1995. 9-21

LIST OF TABLES (continued)

Table Page

9-14 Imports of Selected Petroleum Products by Year, United States, 1969-1979 9-23

9-15 Exports of Selected Petroleum Products by Year, United States, 1969-1978 9-24

9-16 Profit Margins for Major Corporations with Petroleum Refinery Capacity, By Company Type and Year, 1975-1976. 9-26

9-17 Return on Investment for Major Corporations with Petroleum Refining Capacity, By Company Type and Year, 1975-1979. 9-27

9-18 Petroleum Refining Income Data by Quarter, United States Refineries, 1978-1980 9-28

9-19 Revenue Estimation - Model Unit A. 9-30

9-20 Revenue Estimation - Model Unit B. 9-31

9-21 Revenue Estimation - Model Unit C. 9-32

9-22 Annual Revenue Summary by Model Unit 9-33

9-23 Percent Increases in Price Under Full Cost Pricing by Model Unit. 9-38

9-24 Profit Margins Under Full Cost Absorption by Model Unit 9-39

9-25 Summary of Fifth-Year Net Annualized Cost. 9-42

C-1 Sampled Process Units from Nine Refineries C-3

C-2 Leak Frequencies and Emission Factors for Fugitive Sources C-5

C-3 Summary of Components Tested and Percent Leaking in Six Refineries C-6

C-4 Summary of Maintenance Study Results from the Union Oil Company Refinery in Rodeo, California C-10

C-5 Summary of Maintenance Study Results from the Shell Oil Company Refinery in Martinez, California C-12

C-6 Summary of EPA Refinery Maintenance Study Results . . C-13

LIST OF TABLES (continued)

Table | Page

C-7 Maintenance Effectiveness Ethylene Unit Block Valves C-14

C-8 Occurrence Rate Estimates for Valves and Pumps by Process in EPA-ORD Study C-16

C-9 Valve Leak Recurrence Rate Estimates C-17

C-10 Summary of Valve Maintenance Test Results C-18

E-1 Crude Distillation Capacity by Refinery by State, United States and United States Territories, January 1, 1980 . . . . E-2

E-2 Refinery Process Unit Growth Projections (1981-86) . . E-9

F-1 Statistical Analysis System (SAS) Program to Evaluate the Impact of a Maintenance Program on Fugitive Emissions. F-5

F-2 Impact Data for Evaluating the Reduction in Average Leak Rate Due to a Valve Maintenance Program F-16

F-3 Valve Emission Factors and Mass Emission Reductions. . F-17

F-4 Fraction of Valves Screened and Operated On. F-18

F-5 Emission Factors and Mass Emission Reduction for Valves by Inspection Period. F-19

F-6 Fraction of Sources Screened and Operated on for Valves by Month. F-20

F-7 Fractional Distribution of Sources for Valves by Inspection Period. F-24

F-8 Input Data for Examining the Reduction in Average Leak Rate Due to a Pump Maintenance Program. F-28

F-9 Pump Emission Factors and Mass Emission Reduction. . . F-29

F-10 Fraction of Pumps Screened and Operated on. F-30

F-11 Emission Factors and Mass Emission Reduction for Pumps by Inspection Period F-31

F-12 Fraction of Sources Screened and Operated on for Pumps by Month F-32

LIST OF TABLES (continued)

Table Page

F-13 Fractional Distribution of Sources for Pumps by Inspection Period F-34

F-14 Controlled VOC Emission Factors for Various Inspection Intervals Using the LDAR Model. F-37

F-15 VOC Emissions for Regulatory Alternatives Based on LDAR Model F-38

F-16 Annual Model Unit Emissions and Average Percent Emission Reduction From Regulatory Alternative I Based on LDAR Model Results F-41

F-17 Project VOC Fugitive Emissions from Affected Model Units for Regulatory Alternatives for 1982-1986 Based on LDAR Model Results F-42

F-18 Projected Energy Impacts of Regulatory Alternatives for 1982-1986 Based on LDAR Model Results F-43

F-19 Monitoring and Maintenance Labor-Hour Requirements Based on LDAR Model Results F-44

F-20 Leak Detection and Repair Costs Based on LDAR Model Results. F-45

F-21 Recovery Credits F-46

F-22 Annualized Control Cost Estimates for New Facilities for Model Unit A Based on the LDAR Model F-47

F-23 Annualized Control Cost Estimates for New Facilities for Model Unit B Based on the LDAR Model F-48

F-24 Annualized Control Cost Estimates for New Facilities for Model Unit C Based on the LDAR Model F-49

F-25 Cost Effectiveness for Model Units for New Facilities Based on the LDAR Model. F-50

F-26 Annualized Control Cost Estimates for Modified/ Reconstructed Facilities for Model Unit A Based on the LDAR Model. F-51

F-27 Annualized Control Cost Estimates for Modified/ Reconstructed Facilities for Model Unit B Based on the LDAR Model F-52

LIST OF TABLES (concluded)

Table	Page
F-28 Annualized Control Cost Estimates for Modified/ Reconstructed Facilities for Model Unit C Based on the LDAR Model.	F-53
F-29 Fifth-Year Nationwide Costs of the Regulatory Alternatives Above Regulatory Alternative I Costs Based on the LDAR Model.	F-54
F-30 Fifth-Year Nationwide Costs for the Petroleum Industry Above Baseline Costs Based on the LDAR Model	F-55
F-31 Percent Increases in Price Under Full Cost Pricing by Model Unit Based on LDAR Model Results	F-56
F-32 Profit Margins Under Full Cost Absorption by Model Unit Based on LDAR Model Results.	F-57
F-33 Summary of Fifth Year Net Annualized Costs Based on LDAR Model Results	F-57
F-34 Comparison of Results from the LDAR Model with the ABCD Model Analysis.	F-58
F-35 Comparison of Overall Emission and Cost Impacts Using LDAR Model Program Values with ABCD Model Analysis Impacts	F-59

LIST OF FIGURES

Figure Page

3-1 Simplified Flow Chart for a Typical Gasoline Producing Refinery 3-2

3-2 Diagram of a Simple Packed Seal. 3-5

3-3 Diagram of a Basic Single Mechanical Seal. 3-5

3-4 Diagram of a Dual Mechanical Seal (back-to-back arrangement) 3-7

3-5 Diagram of a Dual Mechanical Seal (tandem arrangement) 3-7

3-6 Chempump Canned-motor Pump 3-8

3-7 Shriver Mechanically Actuated Diaphragm Pump 3-8

3-8 Liquid-film Compressor Shaft Seal. 3-10

3-9 Globe Valve with Packed Seal 3-10

3-10 Diagram of a Spring-loaded Relief Valve. 3-12

3-11 Cooling Tower (cross-flow) 3-12

4-1 Seal-less Canned Motor Pump 4-15

4-2 Sealed Bellows Valve 4-18

4-3 Rupture Disk Installation Upstream of a Relief Valve 4-20

4-4 Simplified Closed-Vent System with Dual Flares 4-22

4-5 Diagram of Two Closed-Loop Sampling Systems. 4-24

F-1 Schematic Diagram of the LDAR Model. F-3

F-2 Effect of Leak Repair Cycles on Field Emission Test Results and Leak Detection and Repair Program (LDRP) Effectiveness. F-14

METRIC CONVERSION TABLE

EPA policy is to express all measurements in Agency documents in metric units. Listed below are metric units used in this report with conversion factors to obtain equivalent English units. A list of prefixes to metric units is also presented.

To Convert Metric Unit	Multiply By Conversion Factor	To Obtain English Unit
centimeter (cm)	0.39	inch (in.)
meter (m)	3.28	feet (ft.)
liter (l)	0.26	U.S. gallon (gal)
cubic meter (m^3)	264.2	U.S. gallon (gal)
cubic meter (m^3)	6.29	barrel (oil) (bbl)
cubic meter (m^3)	35	cubic feet (ft^3)
kilogram (kg)	2.2	pound (lb)
megagram (Mg)	1.1	ton
gigagram (Gg)	2.2	million pounds (10^6 lbs)
gigagram (Gg)	1102	ton
joule (J)	9.48×10^{-4}	British thermal unit (Btu)

PREFIXES

Prefix	Symbol	Multiplication Factor
tera	T	10^{12}
giga	G	10^{9}
mega	M	10^{6}
kilo	k	10^{3}
centi	c	10^{-2}
milli	m	10^{-3}
micro	μ	10^{-6}

1.0 SUMMARY

1.1 REGULATORY ALTERNATIVES

Standards of performance for stationary sources of volatile organic compounds (VOC) from fugitive emission sources in the petroleum refining industry are being developed under the authority of Section 111 of the Clean Air Act. These standards would affect new and modified/ reconstructed existing stationary sources of VOC in the petroleum refining industry.

Six regulatory alternatives were considered. Regulatory Alternative I represents the level of control within industry in the absence of new regulations. It provides the basis for comparison of the impacts of the other regulatory alternatives. The requirements for Regulatory Alternative II are based upon the recommendations of the refinery VOC control techniques guideline (CTG) document (EPA-450/2-78-036). The requirements are as follows:

- Quarterly monitoring for leaks from valves in gas service, pressure/relief devices in gas service, and compressor seals (also monitoring relief valves after overpressure relief to detect improper reseating);
- Annual monitoring for leaks from pump seals and valves in light liquid service;
- Weekly visual inspections of pump seals and immediate instrument monitoring of visually leaking pumps; and
- Installation of caps, blind flanges, plugs, or other valves to seal all open-ended lines.

Regulatory Alternative III provides more effective control than Regulatory Alternative II by increasing the frequency of equipment inspections and by specifying additional equipment requirements:

- Quarterly monitoring for leaks from valves in gas and light liquid service;
- Monthly monitoring for leaks from pump seals in light liquid service; and
- Installation of rupture disks on safety/relief valves, mechanical seals with controlled degassing reservoirs on compressors, and closed purge sampling systems.

Regulatory Alternative IV reduces emissions further by specifying equipment for pumps rather than monthly monitoring. Dual mechanical seals with a barrier fluid and degassing reservoir vents would be required on pumps in light liquid service. Other controls would be required as specified for Regulatory Alternative III.

Regulatory Alternative V increases emission control by requiring more frequent inspections on valves in gas and light liquid service. Valves would be monitored monthly. The control requirements for other sources are identical to those required in Regulatory Alternative IV.

Regulatory Alternative VI provides the greatest level of emission reduction by controlling fugitive VOC emissions through additional equipment specifications. In addition to the equipment specifications as required under Regulatory Alternative V, Regulatory Alternative VI requires the installation of sealed bellows valves in gas and light liquid service.

1.2 ENVIRONMENTAL IMPACT

1.2.1 Air Emissions Impact

Total fugitive emissions of VOC from new units in the petroleum refining industry in 1986 are 19.8 gigagrams under Regulatory Alternative I, compared to 6.2, 4.5, 4.1, 3.6 and 1.4 gigagrams under Regulatory Alternatives II through VI. The average percent emissions reductions from the Regulatory Alternative I level effected by Regulatory Alternatives II through VI are 69, 77, 79, 82 and 93 percent, respectively.

For the maximum number of modified and reconstructed units, total VOC fugitive emissions in 1986 are expected to be 43.5 gigagrams under Regulatory Alternative I, compared to 13.6, 9.9, 9.0, 8.0, and 3.1 gigagrams under Regulatory Alternatives II through VI.

1.2.2 Water and Solid Waste Impacts

In addition to reducing emissions to atmosphere, implementation of Regulatory Alternatives II through VI would reduce the waste load on wastewater treatment systems by preventing leakage from process equipment from entering the wastewater system. The impact of solid wastes generated by replacing mechanical seals, rupture disks, plugs, and other metal parts would be insignificant, since these wastes could be recycled.

1.2.3 Energy Impacts

Energy savings would result under Regulatory Alternatives II through VI. Only a minimal increase in energy consumption would result from operation of combustion devices and installation of dual mechanical seals. Assuming recovery of all emission reduction achieved by the regulatory alternatives, the energy savings over a 5-year period from new units would have an energy content ranging from 1,090 terajoules (Regulatory Alternative II) to 1,770 terajoules (Regulatory Alternative VI.) An additional 2,450 to 3,970 terajoules could be recovered from modified and reconstructed units for the same period.

A more detailed analysis of environmental and energy impacts is presented in Chapter 7. A summary of the environmental impacts associated with the six regulatory alternatives is shown in Table 1-1.

1.3 ECONOMIC IMPACT

Cumulative capital and annualized costs, including recovery credits, for the entire petroleum refining industry were estimated for the first five years of implementing each of the regulatory alternatives (1982 - 1986). The estimates for new and modified/reconstructed units are based on May 1980 dollars. Table 1-1 summarizes the economic impacts that result from these costs for each of the regulatory alternatives.

TABLE 1-1. ENVIRONMENTAL AND ECONOMIC IMPACTS OF REGULATORY ALTERNATIVES

Regulatory Alternative	Air Impact	Water Impact	Solid Waste Impact	Energy Impact	Noise Impact	Economic Impact
I (no action)	-4**	-1*	0	0	0	-1**
II	+2**	+1*	0	+1*	0	+1*
III	+3**	+1*	0	+1*	0	0
IV	+3**	+1*	0	+1*	0	-1*
V	+3**	+1*	0	+1*	0	-1*
VI	+4**	+1*	0	+1*	0	-3**

Key:	+	Beneficial impact	0	No impact	*	Short-term impact
	-	Adverse impact	1	Negligible impact	**	Long-term impact
			2	Small impact	***	Irreversible impact
			3	Moderate impact		
			4	Large impact		

During the first five years of implementation of Regulatory Alternative II, the cumulative capital costs for the petroleum refining industry would be $1.8 million for new units and an additional $3.7 million for modified/reconstructed units. In the fifth year, the industry would incur net annualized credits of $1.3 million and $3.3 million for new and modified/reconstructed units, respectively, due to the value of the recovered product.

Under Regulatory Alternative III, cumulative capital costs would be $8.2 million for new units and $19.0 million for modified/reconstructed units. Net annualized costs of $31 thousand for new units and $900 thousand for modified/reconstructed units would be incurred by the industry in 1986.

Under Regulatory Alternative IV, cumulative capital costs for the period from 1981 to 1986 would be $20.0 million and $47.0 million for new units and modified/reconstructed units, respectively. The net annualized costs in the fifth year would be $3.2 million for new units and $7.7 million for modified/reconstructed units.

The 5-year cumulative capital costs as a result of implementing Regulatory Alternative V would be $20.0 million for new units and $47.0 million for modified/reconstructed units. The net annualized costs in the fifth year would be $3.6 million and $9.2 million for new and modified/reconstructed units, respectively.

Regulatory Alternative VI incurs the greatest capital cost and net annualized cost of all the regulatory alternatives. Cumulative capital costs for the industry would be $274.0 million for new units and $610.0 million for modified/reconstructed units. The net annualized costs in 1986 would be $64.1 million for new units and $146.3 million for modified/reconstructed units. A more detailed analysis of costs is included in Chapter 8.

Industry-wide price increases are not expected to result from implementation of any of these regulatory alternatives because the net annualized costs to the industry are an insignificant fraction of the net annual revenues. A more detailed economic analysis is presented in Chapter 9.

2. INTRODUCTION

2.1 BACKGROUND AND AUTHORITY FOR STANDARDS

Before standards of performance are proposed as a Federal regulation, air pollution control methods available to the affected industry and the associated costs of installing and maintaining the control equipment are examined in detail. Various levels of control based on different technologies and degrees of efficiency are expressed as regulatory alternatives. Each of these alternatives is studied by EPA as a prospective basis for a standard. The alternatives are investigated in terms of their impacts on the economics and well-being of the industry, the impacts on the national economy, and the impacts on the environment. This document summarizes the information obtained through these studies so that interested persons will be able to see the information considered by EPA in the development of the proposed standard.

Standards of performance for new stationary sources are established under Section 111 of the Clean Air Act (42 U.S.C. 7411) as amended, hereinafter referred to as the Act. Section 111 directs the Administrator to establish standards of performance for any category of new stationary source of air pollution which "... causes, or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."

The Act requires that standards of performance for stationary sources reflect,"... the degree of emission reduction achievable which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated for that category of sources." The standards apply only to stationary sources, the construction or modification of which commences after regulations are proposed by publication in the Federal Register.

The 1977 amendments to the Act altered or added numerous provisions that apply to the process of establishing standards of performance.

1. EPA is required to list the categories of major stationary sources that have not already been listed and regulated under standards of performance. Regulations must be promulgated for these new categories on the following schedule:

   a. 25 percent of the listed categories by August 7, 1980.
   b. 75 percent of the listed categories by August 7, 1981.
   c. 100 percent of the listed categories by August 7, 1982.

   A governor of a State may apply to the Administrator to add a category not on the list or may apply to the Administrator to have a standard of performance revised.

2. EPA is required to review the standards of performance every four years and, if appropriate, revise them.

3. EPA is authorized to promulgate a standard based on design, equipment, work practice, or operational procedures when a standard based on emission levels is not feasible.

4. The term "standards of performance" is redefined, and a new term "technological system of continuous emission reduction" is defined. The new definitions clarify that the control system must be continuous and may include a low- or non-polluting process or operation.

5. The time between the proposal and promulgation of a standard under Section 111 of the Act may be extended to six months.

Standards of performance, by themselves, do not guarantee protection of health or welfare because they are not designed to achieve any specific air quality levels. Rather, they are designed to reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction, taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impacts, and energy requirements.

Congress had several reasons for including these requirements. First, standards with a degree of uniformity are needed to avoid situations where some States may attract industries by relaxing standards relative to other States. Second, stringent standards enhance the potential for long-term growth. Third, stringent standards may help achieve long-term cost savings by avoiding the need for more retrofitting when pollution ceilings may be reduced in the future. Fourth, certain types of standards for coal-burning sources can adversely affect the coal market by driving up the price of low-sulfur coal or effectively excluding certain coals from the reserve base because their untreated pollution potentials are high. Congress does not intend that new source performance standards contribute to these problems. Fifth, the standard-setting process should create incentives for improved technology.

Promulgation of standards of performance does not prevent State or local agencies from adopting more stringent emission limitations for the same sources. States are free under Section 116 of the Act to establish even more stringent emission limits than those established under Section 111 or those necessary to attain or maintain the National Ambient Air Quality Standards (NAAQS) under Section 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under Section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area that falls under the prevention of significant deterioration of air quality provisions of Part C of the Act. These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology. The term Best Available Control Technology (BACT), as defined in the Act, means

> ... an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from, or which results from, any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best available control technology" result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to Sections 111 or 112 of this Act. (Section 169(3))

Although standards of performance are normally structured in terms of numerical emission limits where feasible, alternative approaches are sometimes necessary. In some cases physical measurement of emissions from a new source may be impractical or exorbitantly expensive. Section 111(h) provides that the Administrator may promulgate a design or equipment standard in those cases where it is not feasible to prescribe or enforce a standard of performance. For example, emissions of hydrocarbons from storage vessels for petroleum liquids are greatest during tank filling. The nature of the emissions, high concentrations for short periods during filling and low concentrations for longer periods during storage, and the configuration of storage tanks make direct emission measurement impractical. Therefore, a more practical approach to standards of performance for storage vessels has been equipment specification.

In addition, Section 111(j) authorizes the Administrator to grant waivers of compliance to permit a source to use innovative continuous emission control technology. In order to grant the waiver, the Administrator must find: (1) a substantial likelihood that the technology will produce greater emission reductions than the standards require or an equivalent reduction at lower economic energy or environmental cost; (2) the proposed system has not been adequately demonstrated; (3) the technology will not cause or contribute to an unreasonable risk to the public health, welfare, or safety; (4) the governor of the State where the source is located consents; and (5) the waiver will not prevent the attainment or maintenance of any ambient standard. A waiver may have conditions attached to assure the source will not prevent attainment of any NAAQS. Any such condition will have the force of a performance standard. Finally, waivers have definite end dates and may be terminated earlier if the conditions are not met or if the system fails to perform as expected. In such a case, the source may be given up to three years to meet the standards with a mandatory progress schedule.

2.2 SELECTION OF CATEGORIES OF STATIONARY SOURCES

Section 111 of the Act directs the Adminstrator to list categories of stationary sources. The Administrator "... shall include a category of sources in such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Proposal and promulgation of standards of performance are to follow.

Since passage of the Clean Air Act of 1970, considerable attention has been given to the development of a system for assigning priorities to various source categories. The approach specifies areas of interest by considering the broad strategy of the Agency for implementing the Clean Air Act. Often, these "areas" are actually pollutants emitted by stationary sources. Source categories that emit these pollutants are evaluated and ranked by a process involving such factors as: (1) the level of emission control (if any) already required by State regulations, (2) estimated levels of control that might be required from standards of performance for the source category, (3) projections of growth and replacement of existing facilities for the source category, and (4) the estimated incremental amount of air pollution that could be prevented in a preselected future year by standards of performance for the source category. Sources for which new source performance standards were promulgated or under development during 1977, or earlier, were selected on these criteria.

The Act amendments of August 1977 establish specific criteria to be used in determining priorities for all major source categories not yet listed by EPA. These are: (1) the quantity of air pollutant emissions that each such category will emit, or will be designed to emit; (2) the extent to which each such pollutant may reasonably be anticipated to endanger public health or welfare; and (3) the mobility and competitive nature of each such category of sources and the consequent need for nationally applicable new source standards of performance.

The Administrator is to promulgate standards for these categories according to the schedule referred to earlier.

In some cases it may not be feasible immediately to develop a standard for a source category with a high priority. This might happen when a program of research is needed to develop control techniques or because techniques for sampling and measuring emissions may require refinement. In the developing of standards, differences in the time required to complete the necessary investigation for different source categories must also be considered. For example, substantially more time may be necessary if numerous pollutants must be investigated from a single source category. Further, even late in the development process the schedule for completion of a standard may change. For example, inability to obtain emission data from well-controlled sources in time to pursue the development process in a systematic fashion may force a change in scheduling. Nevertheless, priority ranking is, and will continue to be, used to establish the order in which projects are initiated and resources assigned.

After the source category has been chosen, the types of facilities within the source category to which the standard will apply must be determined. A source category may have several facilities that cause air pollution, and emissions from some of these facilities may vary from insignificant to very expensive to control. Economic studies of the source category and of applicable control technology may show that air pollution control is better served by applying standards to the more severe pollution sources. For this reason, and because there is no adequately demonstrated system for controlling emissions from certain facilities, standards often do not apply to all facilities at a source. For the same reasons, the standards may not apply to all air pollutants emitted. Thus, although a source category may be selected to be covered by a standard of performance, not all pollutants or facilities within that source category may be covered by the standards.

2.3 PROCEDURE FOR DEVELOPMENT OF STANDARDS OF PERFORMANCE

Standards of performance must (1) realistically reflect best demonstrated control practice; (2) adequately consider the cost, the nonair quality health and environmental impacts, and the energy requirements of such control; (3) be applicable to existing sources that are modified or reconstructed as well as new installations; and (4) meet these conditions for all variations of operating conditions being considered anywhere in the country.

The objective of a program for developing standards is to identify the best technological system of continuous emission reduction that has been adequately demonstrated. The standard-setting process involves three principal phases of activity: (1) information gathering, (2) analysis of the information, and (3) development of the standard of performance.

During the information-gathering phase, industries are queried through a telephone survey, letters of inquiry, and plant visits by EPA representatives. Information is also gathered from many other sources, and a literature search is conducted. From the knowledge acquired about the industry, EPA selects certain plants at which emission tests are conducted to provide reliable data that characterize the pollutant emissions from well-controlled existing facilities.

In the second phase of a project, the information about the industry and the pollutants emitted is used in analytical studies. Hypothetical "model plants" are defined to provide a common basis for analysis. The model plant definitions, national pollutant emission data, and existing State regulations governing emissions from the source category are then used in establishing "regulatory alternatives." These regulatory alternatives are essentially different levels of emission control.

EPA conducts studies to determine the impact of each regulatory alternative on the economics of the industry and on the national economy, on the environment, and on energy consumption. From several possibly applicable alternatives, EPA selects the single most plausible regulatory alternative as the basis for a standard of performance for the source category under study.

In the third phase of a project, the selected regulatory alternative is translated into a standard of performance, which, in turn, is written in the form of a Federal regulation. The Federal regulation, when applied to newly constructed plants, will limit emissions to the levels indicated in the selected regulatory alternative.

As early as is practical in each standard-setting project, EPA representatives discuss the possibilities of a standard and the form it might take with members of the National Air Pollution Control Techniques Advisory Committee. Industry representatives and other interested parties also participate in these meetings.

The information acquired in the project is summarized in the Background Information Document (BID). The BID, the standard, and a preamble explaining the standard are widely circulated to the industry being considered for control, environmental groups, other government agencies, and offices within EPA. Through this extensive review process, the points of view of expert reviewers are taken into consideration as changes are made to the documentation.

A "proposal package" is assembled and sent through the offices of EPA Assistant Administrators for concurrence before the proposed standard is officially endorsed by the EPA Administrator. After being approved by the EPA Administrator, the preamble and the proposed regulation are published in the Federal Register.

As a part of the Federal Register announcement of the proposed regulation, the public is invited to participate in the standard-setting process. EPA invites written comments on the proposal and also holds a public hearing to discuss the proposed standard with interested parties. All public comments are summarized and incorporated into a second volume of the BID. All information reviewed and generated in studies in support of the standard of performance is available to the public in a "docket" on file in Washington, D. C.

Comments from the public are evaluated, and the standard of performance may be altered in response to the comments.

The significant comments and EPA's position on the issues raised are included in the "preamble" of a "promulgation package," which also contains the draft of the final regulation. The regulation is then subjected to another round of review and refinement until it is approved by the EPA Administrator. After the Administrator signs the regulation, it is published as a "final rule" in the Federal Register.

2.4 CONSIDERATION OF COSTS

Section 317 of the Act requires an economic impact assessment with respect to any standard of performance established under Section 111 of the Act. The assessment is required to contain an analysis of: (1) the costs of compliance with the regulation, including the extent to which the cost of compliance varies depending on the effective date of the regulation and the development of less expensive or more efficient methods of compliance; (2) the potential inflationary or recessionary effects of the regulation; (3) the effects the regulation might have on small business with respect to competition; (4) the effects of the regulation on consumer costs; and (5) the effects of the regulation on energy use. Section 317 also requires that the economic impact assessment be as extensive as practicable.

The economic impact of a proposed standard upon an industry is usually addressed both in absolute terms and in terms of the control costs that would be incurred as a result of compliance with typical, existing State control regulations. An incremental approach is necessary because both new and existing plants would be required to comply with State regulations in the absence of a Federal standard of performance. This approach requires a detailed analysis of the economic impact from the cost differential that would exist between a proposed standard of performance and the typical State standard.

Air pollutant emissions may cause water pollution problems, and captured potential air pollutants may pose a solid waste disposal problem. The total environmental impact of an emission source must, therefore, be analyzed and the costs determined whenever possible.

A thorough study of the profitability and price-setting mechanisms of the industry is essential to the analysis so that an accurate estimate of potential adverse economic impacts can be made for proposed standards. It is also essential to know the capital requirements for pollution control systems already placed on plants so that the additional capital requirements necessitated by these Federal standards can be placed in proper perspective. Finally, it is necessary to assess the availability of capital to provide the additional control equipment needed to meet the standards of performance.

2.5 CONSIDERATION OF ENVIRONMENTAL IMPACTS

Section 102(2)(C) of the National Environmental Policy Act (NEPA) of 1969 requires Federal agencies to prepare detailed environmental impact statements on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment. The objective of NEPA is to build into the decisionmaking process of Federal agencies a careful consideration of all environmental aspects of proposed actions.

In a number of legal challenges to standards of performance for various industries, the United States Court of Appeals for the District of Columbia Circuit has held that environmental impact statements need not be prepared by the Agency for proposed actions under Section 111 of the Clean Air Act. Essentially, the Court of Appeals has determined that the best system of emission reduction requires the Administrator to take into account counter-productive environmental effects of a proposed standard, as well as economic costs to the industry. On this basis, therefore, the Court established a narrow exemption from NEPA for EPA determination under Section 111.

In addition to these judicial determinations, the Energy Supply and Environmental Coordination Act (ESECA) of 1974 (PL-93-319) specifically exempted proposed actions under the Clean Air Act from NEPA requirements. According to Section 7(c)(1), "No action taken under the Clean Air Act shall be deemed a major Federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act of 1969." (15 U.S.C. 793(c)(1))

Nevertheless, the Agency has concluded that the preparation of environmental impact statements could have beneficial effects on certain regulatory actions. Consequently, although not legally required to do so by Section 102(2)(C) of NEPA, EPA has adopted a policy requiring that environmental impact statements be prepared for various regulatory actions, including standards of performance developed under Section 111 of the Act. This voluntary preparation of environmental impact statements, however, in no way legally subjects the Agency to NEPA requirements.

To implement this policy, a separate section in this document is devoted solely to an analysis of the potential environmental impacts associated with the proposed standards. Both adverse and beneficial impacts in such areas as air and water pollution, increased solid waste disposal, and increased energy consumption are discussed.

2.6 IMPACT ON EXISTING SOURCES

Section 111 of the Act defines a new source as "... any stationary source, the construction or modification of which is commenced ..." after the proposed standards are published. An existing source is redefined as a new source if "modified" or "reconstructed" as defined in amendments to the general provisions of Subpart A of 40 CFR Part 60, which were promulgated in the Federal Register on December 16, 1975 (40 FR 58416).

Promulgation of a standard of performance requires States to establish standards of performance for existing sources in the same industry under Section 111(d) of the Act if the standard for new sources limits emissions of a designated pollutant (i.e., a pollutant for which air quality criteria have not been issued under Section 108 or which has not been listed as a hazardous pollutant under Section 112). If a State does not act, EPA must establish such standards. General provisions outlining procedures for control of existing sources under Section 111(d) were promulgated on November 17, 1975, as Subpart B of 40 CFR Part 60 (40 FR 53340).

2.7 REVISION OF STANDARDS OF PERFORMANCE

Congress was aware that the level of air pollution control achievable by any industry may improve with technological advances. Accordingly, Section 111 of the Act provides that the Administrator "... shall, at least every 4 years, review and, if appropriate, revise ..." the standards. Revisions are made to assure that the standards continue to reflect the best systems that become available in the future. Such revisions will not be retroactive, but will apply to stationary sources constructed or modified after the proposal of the revised standards.

3.0 DESCRIPTION OF PETROLEUM REFINERY FUGITIVE VOC EMISSION SOURCES

3.1 INTRODUCTION AND GENERAL INDUSTRY INFORMATION

3.1.1 Introduction

The intent of this chapter is to define the petroleum refining industry and describe the potential fugitive VOC emission sources that are typically found in the petroleum refining industry. The leak rates of uncontrolled emissions from the various fugitive VOC emission sources are quantified where possible.

3.1.2 General Information

A petroleum refinery is defined as any facility that is engaged in the production of gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, or other products through the distillation of petroleum, or through the redistillation, cracking, rearrangement, or reforming of unfinished petroleum derivatives. The type and complexity of the processes in operation at an individual refinery vary depending on the crude oil composition (e.g., paraffinic, napthenic, and aromatic hydrocarbon content; sulfur content; and metals content) and on the types of finished products desired.

Figure 3-1 presents a generalized flow diagram for a refinery maximizing gasoline production. Each process unit is comprised of a set of components or equipment pieces such as valves, pumps, flanges, etc., that are used to move and control the flow of organic compounds to and from various process vessels. Equipment pieces represent potential fugitive VOC emission sources whenever they handle a process stream containing organic compounds. For example, some sources develop leaks after some period of operation due to the failure of sealing mechanisms. These could include pumps, compressors, valves, flanges, and safety/relief valves. Other types of equipment emit VOC

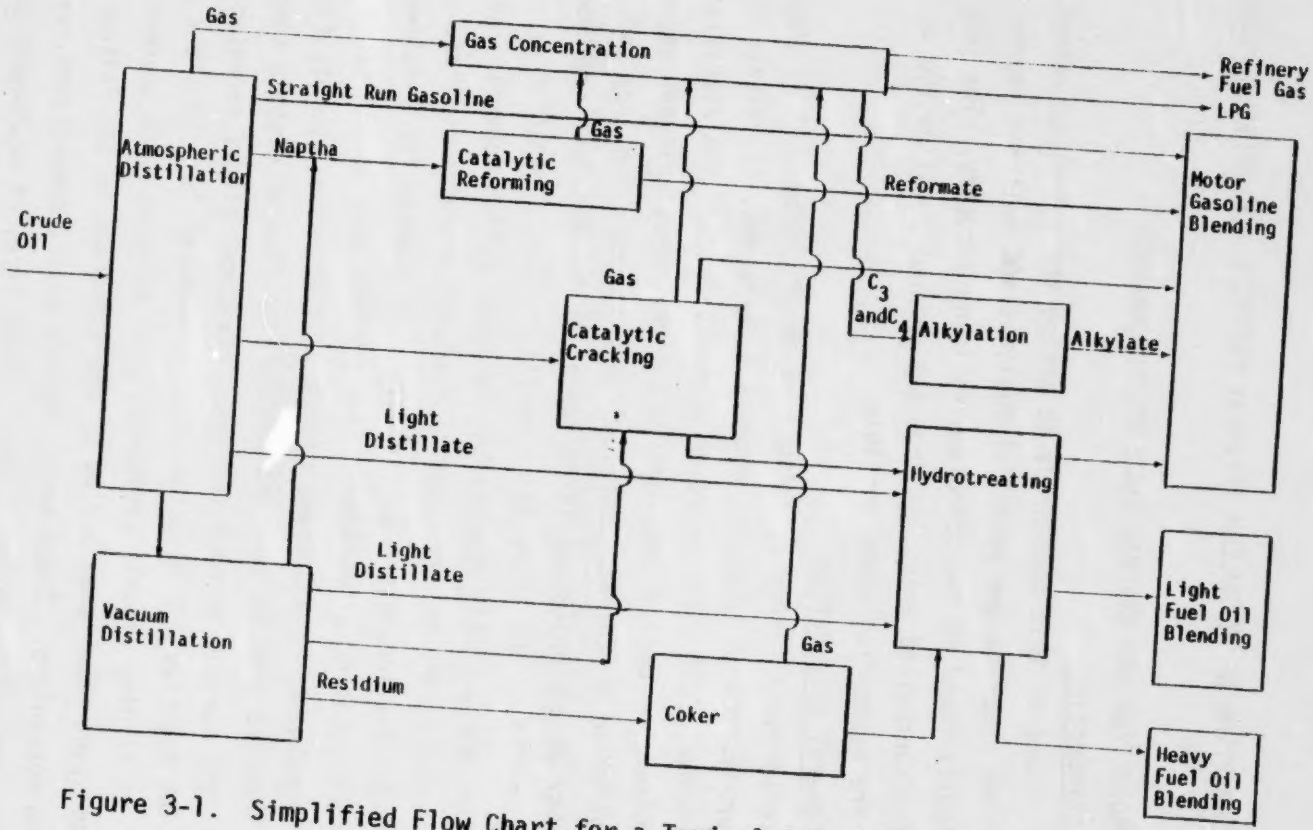
Gas
Gas Concentration
Refinery Fuel Gas
LPG
Straight Run Gasoline
Gas
Atmospheric Distillation
Naptha
Catalytic Reforming
Reformate
Crude Oil
Motor Gasoline Blending
Gas
C_3 and C_4
Alkylation
Alkylate
Catalytic Cracking
Light Distillate
Hydrotreating
Light Distillate
Vacuum Distillation
Light Fuel Oil Blending
Gas
Residium
Coker
Heavy Fuel Oil Blending

Figure 3-1. Simplified Flow Chart for a Typical Gasoline Producing Refinery

intermittently, and only under certain scheduled operating circumstances, such as sampling connections during sampling or open-ended lines during venting. Other unscheduled intermittent VOC sources would include emissions from safety/relief valves during upset conditions. Cooling towers and wastewater separators are highly variable VOC emission sources depending on the characteristics of the material being cooled or separated.

3.2 FUGITIVE EMISSION DEFINITION AND POTENTIAL SOURCE DESCRIPTION

3.2.1 Definition

In this study, fugitive emissions in the petroleum refining industry are considered to be those volatile organic compound (VOC) emissions that result when petroleum fluids (either liquid or gaseous) are emitted from plant equipment. Exempted from this study are fugitive emission sources that have been designated as affected sources by other standards of performance and facilities involved in the production of natural gasoline from natural gas.

3.2.2 Potential Source Characterization and Description

There are many potential sources of VOC fugitive emissions in a typical petroleum refinery. The following sources are considered in this chapter: pumps, compressors, in-line process valves, safety/relief valves, open-ended valves, sampling connections, flanges, cooling towers, and wastewater separators. These potential sources are described below.

3.2.2.1 Pumps. Pumps are used extensively in the petroleum refining industry for the movement of organic fluids. The centrifugal pump is the most widely used pump; however, other types, such as the positive-displacement, reciprocating, rotary action, and special canned and diaphragm pumps, are also used in this industry. Petroleum fluids transferred by centrifugal pumps can leak at the point of contact between the moving shaft and stationary casing. Consequently, a seal is usually required at the point where the shaft penetrates the housing in order to isolate the pump's interior from atmosphere.

Two generic types of sealing devices, packed and mechanical, are currently in use on pumps in the petroleum refining industry. Packed seals can be used on both centrifugal and reciprocating types of pumps. As Figure 3-2 shows, a packed seal consists of a cavity ("stuffing box") in the pump casing filled with special packing material that is compressed with a packing gland to form a seal around the shaft. To prevent the buildup of frictional heat between the seal and shaft, lubrication is required. A sufficient amount of either the liquid being pumped or another liquid that is injected must be allowed to flow between the packing and the shaft to provide the necessary lubrication. Deterioration of this packing and/or the shaft seal face after a period of usage can be expected to eventually result in leakage of organic compounds to atmosphere.

Mechanical seals are limited in application to pumps with rotating shafts and can be further categorized as single and dual mechanical seals. There are many variations to the basic design of mechanical seals, but all have a lapped seal face between a stationary element and a rotating seal ring. In a single mechanical seal application (Figure 3-3), the rotating-seal ring and stationary element faces are lapped to a very high degree of flatness to maintain contact throughout their entire mutual surface area. As with pump packing, mechanical seal faces must be lubricated to remove frictional heat; however, because of the seal's construction, much less lubricant is needed.

A mechanical seal is not a leak-proof device. If the seal becomes imperfect due to wear, the organic compounds being pumped can leak between the seal faces and be emitted to atmosphere.

In a dual mechanical seal application, two seals can be arranged back-to-back or in tandem. In the back-to-back arrangement (Figure 3-4), the two seals provide a closed cavity between them. A barrier fluid is circulated through the cavity. Because the barrier fluid surrounds the dual seal and lubricates both sets of seal faces in this arrangement, the heat transfer and seal life characteristics are much better than those of the single seal. In order for the seal to function, the barrier fluid must be at a pressure greater than the operating pressure of the stuffing box. As a result some barrier fluid will leak across the seal faces. Liquid leaking across the inboard face will enter the stuffing box and mix with the petroleum liquid. Barrier fluid going across the outboard face will exit to atmosphere. Therefore, the barrier fluid must be compatible with the petroleum liquid as well as with the environment.[3]

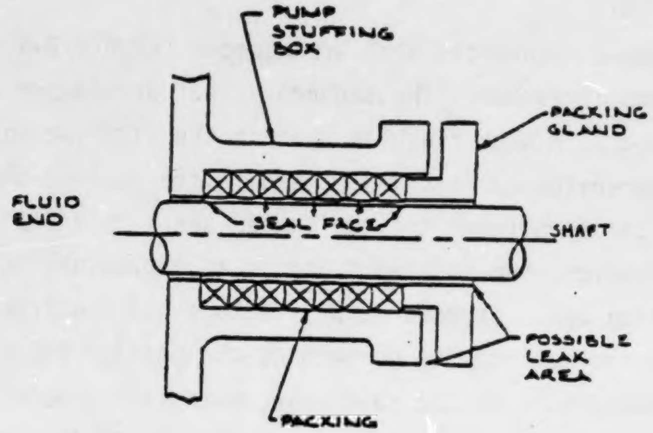
PUMP STUFFING BOX
PACKING GLAND
FLUID END
SEAL FACE
SHAFT
POSSIBLE LEAK AREA
PACKING

Figure 3-2. Diagram of a simple packed seal.[1]

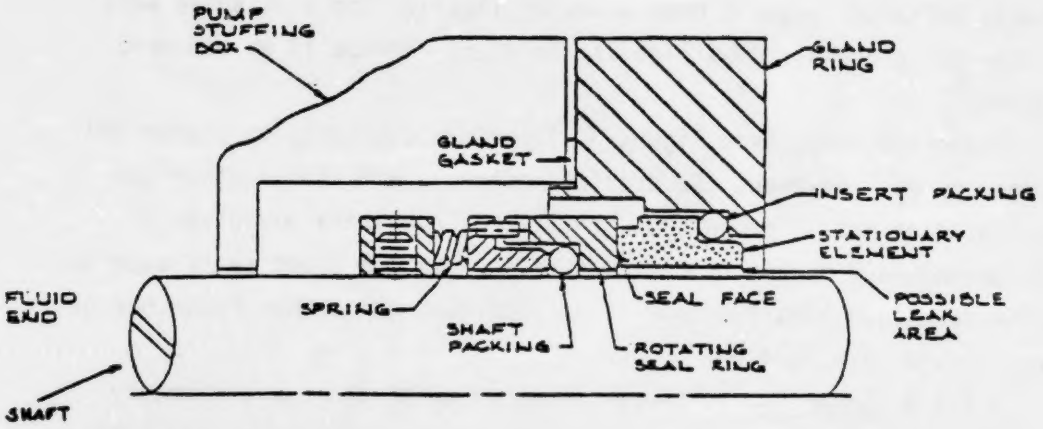
PUMP STUFFING BOX
GLAND RING
GLAND GASKET
INSERT PACKING
STATIONARY ELEMENT
FLUID END
SPRING
SEAL FACE
POSSIBLE LEAK AREA
SHAFT PACKING
ROTATING SEAL RING
SHAFT

Figure 3-3. Diagram of a basic single mechanical seal[2]

In a tandem dual mechanical seal arrangement (Figure 3-5), the seals face the same direction. The secondary seal provides a backup for the primary seal. A seal flush is used in the stuffing box to remove the heat generated by friction. As with the back-to-back seal arrangement, the cavity between the two tandem seals is filled with a barrier fluid. However, the barrier fluid is at a pressure lower than that in the stuffing box. Therefore, any leakage will be from the stuffing box into the seal cavity containing the barrier fluid. Since this liquid is routed to a closed reservoir, petroleum liquid that has leaked into the seal cavity will also be transferred to the reservoir. At the reservoir, the petroleum liquid could vaporize and be emitted to atmosphere. To ensure that VOCs do not leak from the reservoir, the reservoir can be vented to a control device.[4]

Another type of pump that has been used in the petroleum refining industry is the sealless pump which includes canned-motor and diaphragm pumps. In canned-motor pumps (Figure 3-6) the cavity housing, the motor rotor, and the pump casing are interconnected. As a result, the motor bearings run in the pumped liquid, and shaft seals are eliminated. Because the liquid is the bearing lubricant, abrasive solids cannot be tolerated. Canned-motor pumps are being widely used for handling organic solvents, organic heat transfer liquids, light oils, as well as many toxic or hazardous liquids, or where leakage is an economic problem.[5]

Diaphragm pumps (see Figure 3-7) perform similarly to piston and plunger pumps. However, the driving member is a flexible diaphragm fabricated of metal, rubber, or plastic. The primary advantage of this arrangement is the elimination of packing and shaft seals exposed to the petroleum liquid. This is an important asset when hazardous or toxic liquids are handled.[6]

3.2.2.2 Compressors. Three types of compressors are commonly used in the refining industry: centrifugal, reciprocating, and rotary. The centrifugal compressor utilizes a rotating element or series of elements containing curved blades to increase the pressure of a gas by centrifugal force. Reciprocating and rotary compressors increase pressure by confining the gas in a cavity and progressively decreasing

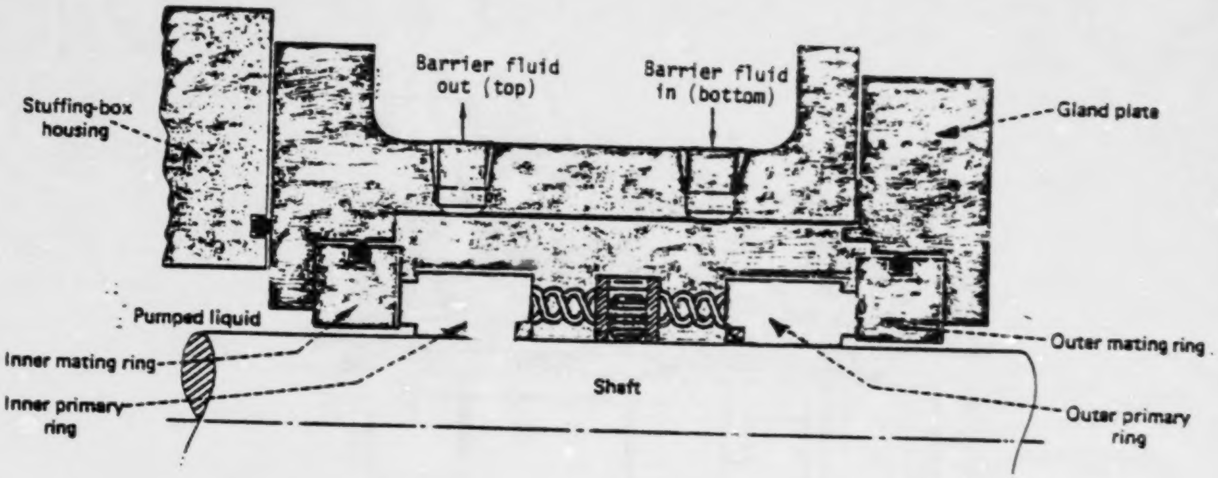
Stuffing-box housing
Barrier fluid out (top)
Barrier fluid in (bottom)
Gland plate
Pumped liquid
Inner mating ring
Inner primary ring
Shaft
Outer mating ring
Outer primary ring

Figure 3-4. Diagram of a dual mechanical seal (back to back arrangement).[7]

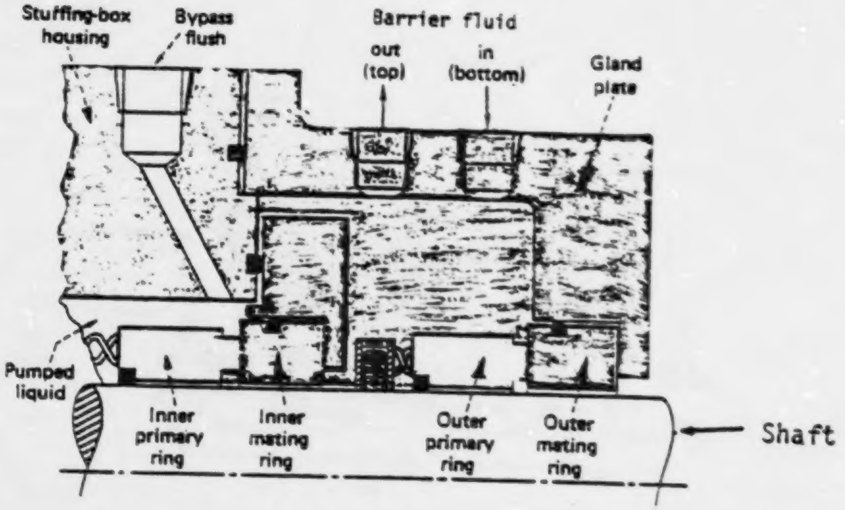
Stuffing-box housing
Bypass flush
Barrier fluid
out (top)
in (bottom)
Gland plate
Pumped liquid
Inner primary ring
Inner mating ring
Outer primary ring
Outer mating ring
Shaft

Figure 3-5. Diagram of a dual mechanical seal (tandem arrangement).[8]

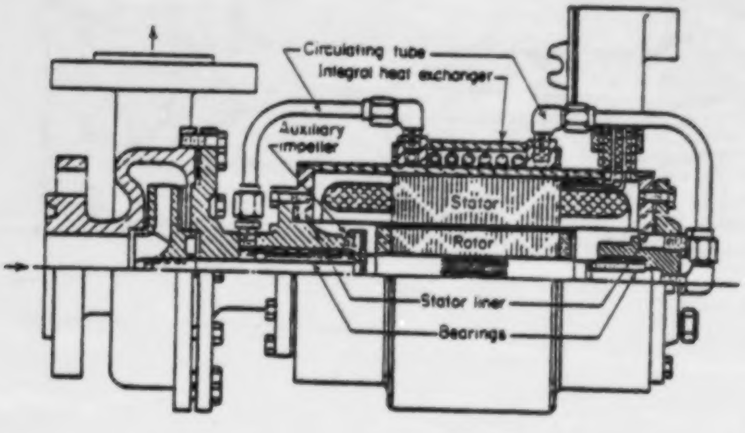
Circulating tube
Integral heat exchanger
Auxiliary impeller
Stator
Rotor
Stator liner
Bearings

Figure 3-6. Chempump canned-motor pump[9]

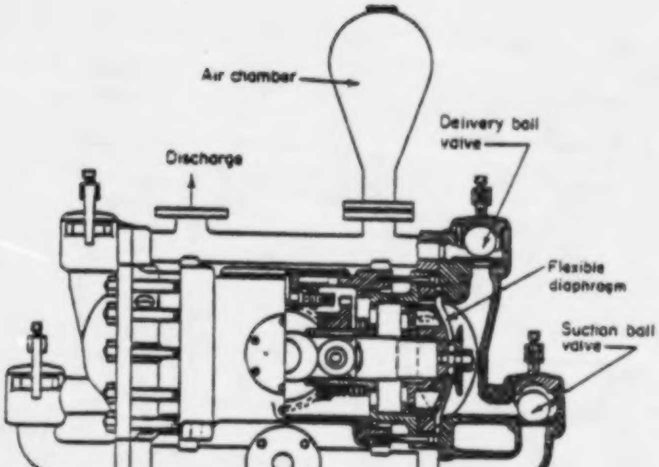
Air chamber
Discharge
Delivery ball valve
Flexible diaphragm
Suction ball valve
Suction

Figure 3-7. Shriver mechanically actuated diaphragm pump.[10]

the volume of the cavity. Reciprocating compressors usually employ a piston and cylinder arrangement while rotary compressors utilize rotating elements such as lobed impellers or sliding vanes.

As with pumps, sealing devices are required to prevent leakage from compressors. Packed seals, mechanical seals, or liquid film seals (Figure 3-8) can be used to limit leakage from compressors that employ rotating drive shafts. For reciprocating compressors, various arrangements of packing glands and packing must be used for this purpose.

3.2.2.3 Process Valves. One of the most common pieces of equipment in refineries is the valve. The types of valves commonly used are globe, gate, plug, ball, relief, and check valves. All except the relief valve and check valve are activated by a valve stem, which may have either a rotational or linear motion, depending on the specific design. This stem requires a seal to isolate the process fluid inside the valve from atmosphere as illustrated by the diagram of a globe valve in Figure 3-9. The possibility of a leak through this seal makes it a potential source of VOC fugitive emissions. Since check valves do not have an external actuating mechanism in contact with process fluids, they are not considered to be potential sources of VOC fugitive emissions.

Sealing of the stem to prevent leakage can be achieved by packing inside a packing gland or O-ring seals. Valves that require the stem to move in and out with or without rotation must utilize a packing gland. Conventional packing glands are suited for a wide variety of packing materials; the most common are various types of braided asbestos that contain lubricants. Other packing materials include graphite, graphite-impregnated fibers, and tetrafluorethylene; the packing material used depends on the valve application and configuration.[13] These conventional packing glands can be used over a wide range of operating temperatures. At high pressures these glands must be quite tight to attain a good seal.[14]

Elastomeric O-rings are also used for sealing process valves. These O-rings provide good sealing but are not suitable where there is sliding motion through the packing gland. These seals are rarely used in high pressure service, and operating temperatures are limited by the seal material.[15]

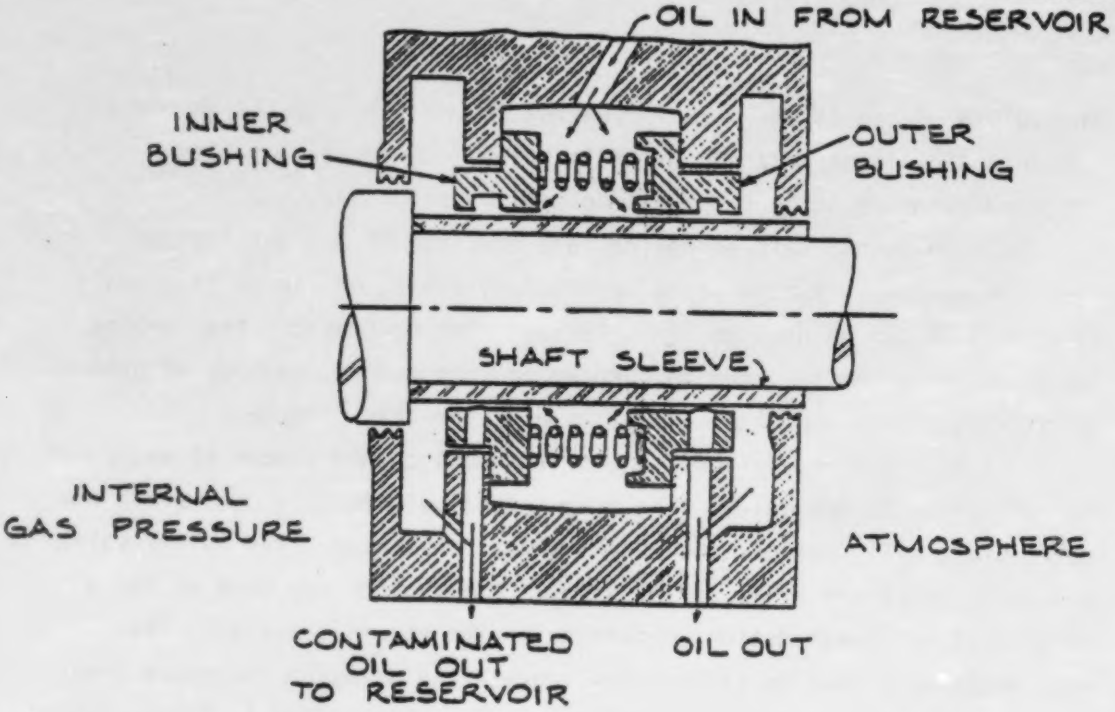
OIL IN FROM RESERVOIR
INNER BUSHING
OUTER BUSHING
SHAFT SLEEVE
INTERNAL GAS PRESSURE
ATMOSPHERE
CONTAMINATED OIL OUT TO RESERVOIR
OIL OUT

Figure 3-8. Liquid-film compressor shaft seal.[11]

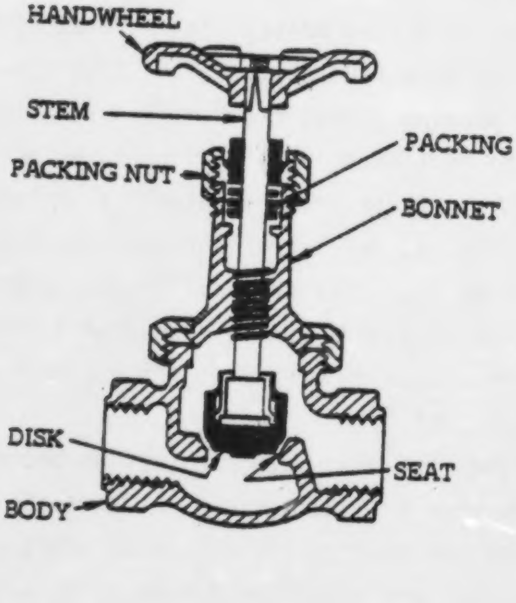
HANDWHEEL
STEM
PACKING
PACKING NUT
BONNET
DISK
SEAT
BODY

Figure 3-9. Globe valve with packed seal[12]

3.2.2.4 Pressure Relief Devices. Engineering codes require that pressure-relieving devices or systems be used in applications where the process pressure may exceed the maximum allowable working pressure of the vessel. The most common type of pressure-relieving device used in the petroleum refining industry is the pressure relief valve (Figure 3-10). Typically, relief valves are spring-loaded and designed to open when the process pressure exceeds a set pressure, allowing the release of vapors or liquids until the system pressure is reduced to its normal operating level. When the normal pressure is reattained, the valve reseats, and a seal is again formed.[16] The seal is a disk on a seat, and the possibility of a leak through this seal makes the pressure relief valve a potential source of VOC fugitive emissions. Two potential causes of leakage from relief valves are: (1) "simmering" or "popping," a condition due to the system pressure being close to the set pressure of the valve, and (2) improper reseating of the valve after a relieving operation.[17]

Rupture disks are also common in the petroleum refining industry. These disks are made of a material that ruptures when a set pressure is exceeded, thus allowing the system to depressurize. The advantage of a rupture disk is that the disk seals tightly and does not allow any VOC to escape from the system under normal operation. However, when the disk does rupture, and a relief valve is not in series with the rupture disk, the system depressurizes until atmospheric conditions are obtained; this could result in an excessive loss of product or correspondingly an excessive release of VOC fugitive emissions.

3.2.2.5 Cooling Towers. Cooling towers (Figure 3-11) dissipate heat from water used to cool process equipment such as reactors, condensers, and heat exchangers. Cooling water is circulated through process units and returned to a cooling tower where the water is evaporatively cooled by forced air circulation. Petroleum fluids can enter the cooling water from leaking process equipment if the equipment is operating at a pressure greater than that of the cooling water. VOCs can be released to atmosphere as cooling water vaporizes in the tower.

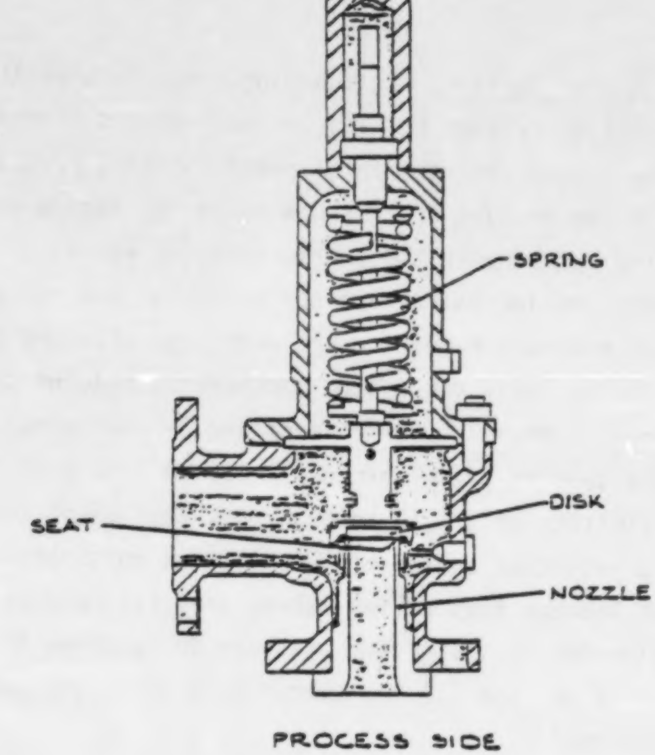
SPRING
DISK
SEAT
NOZZLE
PROCESS SIDE

Figure 3-10. Diagram of a spring-loaded relief valve.[18]

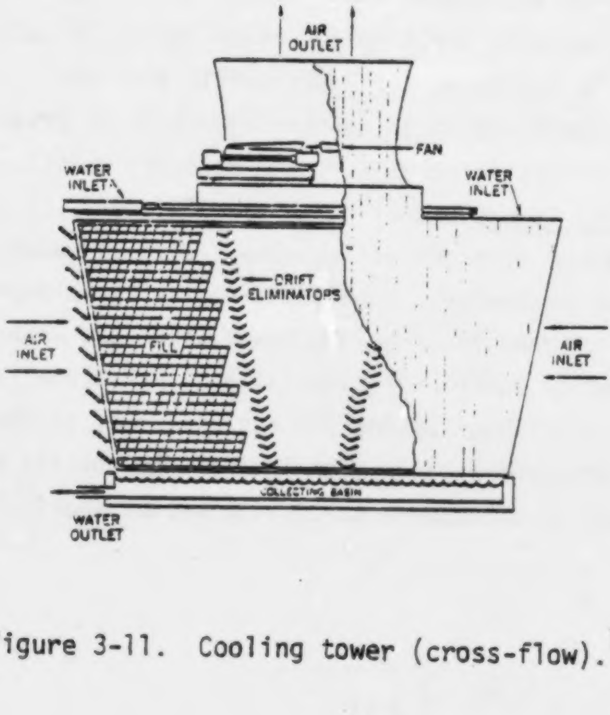
AIR OUTLET
FAN
WATER INLET
WATER INLET
DRIFT ELIMINATORS
AIR INLET
FILL
AIR INLET
COLLECTING BASIN
WATER OUTLET

Figure 3-11. Cooling tower (cross-flow).[19]

3.2.2.6 Wastewater Separators. Contaminated wastewater can originate from several sources including, but not limited to, leaks, spills, pump and compressor seal cooling and flushing, sampling equipment cleaning, stripped sour water, desalter water effluent, and rain runoff. Contaminated wastewater is collected in the process drain system and directed to the wastewater treatment system where oil is skimmed in a separator, and the wastewater undergoes additional treatment as required. Organic compounds can be emitted wherever wastewater is exposed to atmosphere due to evaporation of organic compounds contained in the wastewater. As such, the primary emission points include surface of forebays and separators.

3.2.2.7 Open-Ended Lines. Some valves are installed in a system so that they function with the downstream line open to atmosphere. Open-ended lines are used mostly in intermittent service for sampling and venting. Examples are purge, drain and sampling lines. Some open-ended lines are needed to preserve product purity. These are normally installed between multi-use product lines (e.g., in load-out racks) to prevent products from collecting in cross-tie lines due to valve seat leakage. In addition to valve seat leakage, an incompletely closed valve could result in VOC emissions to the atmosphere.

3.2.2.8 Sampling Connections. The operation of a process unit is checked periodically by routine analyses of feedstocks and products. To obtain representative samples for these analyses, sampling lines must first be purged prior to sampling. The purged liquid or vapor is sometimes drained onto the ground or into a sewer drain, where it can evaporate and release VOC emissions to atmosphere.

3.2.2.9 Flanges. Flanges are bolted, gasket-sealed junctions used wherever pipe or other equipment, such as vessels, pumps, valves, and heat exchangers, may require isolation or removal. Normally, flanges are employed for pipe diameters of 50 mm or greater and are classified by pressure and face type.

Flanges may become VOC fugitive emission sources when leakage occurs due to improperly chosen gaskets or a poorly assembled flange. The primary cause of flange leakage is due to thermal stress that piping or flanges in some services undergo; this results in the deformation of the seal between the flange faces.[20]

3.2.2.10 Blowdown Systems. Refinery process units are periodically shutdown and emptied for internal inspection and maintenance. The process of unit shutdown, repair or inspection, and start-up is termed a unit turnaround. Purging the contents of a vessel to provide a safe interior for workmen is termed a vessel blowdown.

In a typical process unit turnaround, the liquid contents of the vessel are pumped to a storage facility. The vessel is then depressurized, flushed with water, steam, or nitrogen, and ventilated. The vapor content of the vessel may be vented to a fuel gas system, flared, or released directly to atmosphere. When vapors are released directly to atmosphere, it is through a knockout drum (which removes condensible vapors) and a blowdown stack which is usually remotely located to ensure that combustible mixtures are not released within the refinery.

3.3 BASELINE CONTROL

3.3.1 Industrial Practices

In the past, the petroleum refining industry has generally not monitored equipment for fugitive VOC emissions nor repaired equipment on the basis of reducing the level of fugitive VOC emissions. While leaks that are physically evident (leaks that can be seen, heard, or smelled) are normally repaired to minimize product loss and prevent safety hazards, a significant number of fugitive VOC emission sources are not so "easily detectable."

In most nonattainment areas, the States or local agencies have or are in the process of adopting rules similar to the EPA Guideline Series, Control of Volatile Organic Compound Leaks from Petroleum Refinery Equipment, EPA-450/2-78-036.[21] With full implementation by 1983, these rules are expected to affect about 56 percent of existing refineries.[22]

3.3.2 Magnitude of VOC Emissions from Refinery Production Operations

To illustrate the potential magnitude of fugitive VOC emissions from refinery operations, emissions were estimated from a hypothetical 10-unit petroleum refinery (approximately 15,900 m^3/day capacity) as presented in Table 3-2. The number of pieces of each equipment type were multiplied by their respective uncontrolled emission factors given in Table 3-1. Table 3-2 also shows the percentage of the total uncontrolled emissions contributed by each source.

TABLE 3-1. UNCONTROLLED FUGITIVE EMISSION FACTORS IN THE PETROLEUM REFINING INDUSTRY

Fugitive emission source	Uncontrolled emission factor,[a] kg/day
Pump seals	
Light liquids[b]	2.7
Heavy Liquids[c]	0.50
Valves	
Gas	0.64
Light liquid[b]	0.26
Heavy liquid[c]	0.005
Safety/relief valves	
Gas	3.9
Open-ended lines	0.055
Flanges	0.007
Sampling connections	0.36
Compressor seals	15

[a] These uncontrolled emission levels are based upon the refinery data presented in reference 23.

[b] Light liquid is defined as a petroleum liquid with a vapor pressure greater than the vapor pressure of kerosene.

[c] Heavy liquid is defined as a petroleum liquid with a vapor pressure equal to or less than that of kerosene.

Table 3-2. ESTIMATED FUGITIVE VOC EMISSIONS FROM A HYPOTHETICAL 10-UNIT PETROLEUM REFINERY

($15,900\ m^3$/Day Capacity)

Equipment type	Number of pieces of equipment[a]	Uncontrolled emissions[b] kg/day	Percentage of total emissions
Pump Seals			
Light liquids	125	340	4
Heavy liquids	125	62	1
Valves			
Gas	6,000	3,800	47
Light liquid	9,750	2,500	31
Heavy liquid	9,750	50	1
Safety/relief valves			
Gas	130	500	6
Open-ended lines	1,750	96	1
Flanges	64,000	400	5
Sampling connections	250	90	1
Compressor Seals	14	210	3
Totals	93,339	8,048	

[a] Reference 24.

[b] The number of equipment pieces multiplied by their uncontrolled emission factors (given in Table 3-1) yields the uncontrolled emissions per refinery.

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4.0 EMISSION CONTROL TECHNIQUES

4.1 INTRODUCTION

This chapter discusses control techniques that can be applied to reduce fugitive VOC emissions from petroleum refining operations. In general, two approaches to emission control are available. The first entails a leak detection and repair program in which fugitive sources are located and repaired at certain intervals. The second is a preventive approach whereby potential fugitive sources are controlled either by installing specified controls or leakless equipment. The following details the technical application of these control methods and their estimated effectiveness.

4.2 LEAK DETECTION AND REPAIR PROGRAMS

Chapter 3 discusses the types of equipment that have the potential to become fugitive VOC emission sources (i.e., pumps, compressors, etc.). When such a piece of equipment develops a leak, the leak can be detected by various techniques. Once detected, leaks can be repaired through repair procedures, such as tightening the packing for valves.

4.2.1 Leak Detection Techniques

Various monitoring techniques that can be used in a leak detection program include individual component surveys, unit area (walk-through) surveys, and fixed-point monitoring systems. These emission measurement methods would yield qualitative indications of leaks.

4.2.1.1 Individual Component Survey. Each fugitive emission source (e.g., pump, valve, compressor) is checked for VOC leakage in an individual component survey. Two individual component survey methods were identified as follows: (1) leak detection by spraying each component with a soap solution and observing bubble formation and (2) leak detection by measuring VOC concentration with a portable VOC detector.

In the first method, if the soap solution forms bubbles or is blown away, a leak from the component is indicated. However, the magnitude of leak rates based on bubble formation is difficult to assess. In addition, soap bubble formation does not distinguish VOC emissions from other leaking gases or vapors, and bubble formation is subject to component temperature and component configuration restraints.

In the second method, a portable hydrocarbon detector is used to identify leaks of VOC from equipment components. The instrument samples and analyzes the air in close proximity to the potential leak surface by traversing the sampling probe tip over the entire area where leaks may occur. The hydrocarbon concentration of the sampled air is displayed on the instrument meter. This meter reading provides a reasonable qualitative assessment of whether a source is leaking. Performance criteria for the instrument and a description of the leak testing methods are given in Appendix D. Data from petroleum refineries have been used to develop approximate relationships between instrument meter readings and mass emission rates. The data also indicate that variations in mass emission rate and meter reading may occur over short time periods for an individual piece of equipment. More frequent monitoring intervals, therefore, tend to enhance the detection of "large leaks" because there would be more opportunities to find the high leak periods. Table 4-1 shows the percentage of pieces of equipment that are predicted to have meter readings greater than or equal to certain concentrations during an individual component survey.

4.2.1.2 Unit Area Survey. A unit area or walk-through survey entails measuring the ambient VOC concentration within a given distance (for example, one meter) of all equipment located on ground and other accessible levels within a processing area. These measurements are performed with a portable VOC detection instrument utilizing a strip chart recorder.

The instrument operator walks a predetermined path to assure total available coverage of a unit on both the upwind and downwind sides of the equipment, noting on the chart record the location in a unit where any elevated VOC concentrations are detected. If an elevated VOC concentration is recorded, the components in that area can be screened individually to locate the specific leaking equipment.

Table 4-1. PERCENTAGE OF SOURCES PREDICTED TO BE LEAKING IN AN INDIVIDUAL COMPONENT SURVEY[1]

Equipment Type[a]	Predicted Percent of Sources Leaking			
	≥100,000 ppmv	≥50,000 ppmv	≥10,000 ppmv	≥1,000ppmv
Pump Seals				
Light Liquid[b]	7	9	24	49
Heavy Liquid[c]	0	0	2	12
Valves				
Gas[d]	4	5	10	22
Light Liquid[b]	2	4	11	25
Heavy Liquid[c]	0	0	0	1
Safety/Relief Valves (Gas)[d]	1	2	7	19
Pipeline Flanges	0	0	0	2
Compressor Seals	7	13	36	68

[a] This type of information would not be appropriate for open-ended lines, sampling connections, wastewater separators, vacuum producing systems, cooling towers, and relief valve over-pressure.

[b] Light liquid is defined as a petroleum liquid with a vapor pressure greater than the vapor pressure of kerosene.

[c] Heavy liquid is defined as a petroleum liquid with a vapor pressure equal to or less than that of kerosene.

[d] Equipment in gas service contain process fluid in the gaseous state.

It is estimated that 50 percent of all significant leaks in a unit are detected by the walk-through survey, provided that there are only a few pieces of leaking equipment, thus reducing the VOC background concentration sufficiently to allow for reliable detection.[2]

The major advantages of the unit area survey are that leaks from accessible leak sources near the ground can be located quickly and that the leak detection manpower requirements can be lower than those for the individual component survey. Some of the shortcomings of this method are that VOC emissions from adjacent units can cause false leak indications; high or intermittent winds (local meteorological conditions) can increase dispersion of VOC, causing leaks to be undetected; elevated equipment leaks are not detected; and additional effort is necessary to locate the specific leaking equipment (i.e., individual checks in areas where high concentrations are found).

4.2.1.3 Fixed-Point Monitors. This method consists of placing several automatic hydrocarbon sampling and analysis instruments at various locations in the process unit. The instruments may sample the ambient air intermittently or continuously. Elevated hydrocarbon concentrations indicate a leaking component. As in the walk-through method, an individual component survey is required to identify the specific leaking component in the area. Leaks from adjacent units and meteorological conditions may affect the results obtained. The efficiency of this method is not well established, but it has been estimated that 33 percent of the number of leaks identified by a complete individual component survey could be located by fixed-point monitors.[3] Fixed-point monitors operate continuously, however, so that the leaks that are detected would be detected sooner than they would if a periodic component survey were used. Fixed-point monitors are more expensive; multiple units may be required; and the portable instrument is also required to locate the specific leaking component. Calibration and maintenance costs may be higher. Fixed-point monitors have been used to detect emissions of hazardous or toxic substances (such as vinyl chloride) as well as potentially explosive conditions. Fixed-point monitors have an advantage in these cases, since a particular compound can be selected as the sampling criterion.

4.2.1.4 Visual Inspections. Visual inspections can be performed for any of the leak detection techniques discussed above to detect evidence of liquid leakage from plant equipment. When such evidence is observed, the operator can use a portable VOC detection instrument to measure the VOC concentration of the source. In a specific application, visual inspections can be used to detect the failure of the outer seal of a pump dual mechanical seal system. Observation of liquid leaking along the shaft indicates an outer seal failure and signals the need for seal repair.[4]

4.2.2 Repair Techniques

When leaks are located by the leak detection methods described in this section, the leaking component can then be repaired or replaced. Many components can be serviced on-line. This is generally regarded as routine maintenance to keep operating equipment functioning properly. Equipment failure, as indicated by a leak not eliminated by servicing, requires isolation of the faulty equipment for either repair or replacement.

4.2.2.1 Pumps. Most critical service process pumps are backed up with a spare so that they can be isolated for repair. Of those pumps that are not backed up with spares, some can be corrected by on-line repairs (e.g., tightening the packing). However, most leaks that need correction require that the pump be removed from service for seal repair.

4.2.2.2 Valves. Most valve leaks can be reduced on-line by tightening the packing gland for valves with packed seals or by lubrication for plug valves, for example. Based on field observations, one refinery study assumed that 75 percent of leaking valves could be repaired on-line.[5] Age can be an important factor in on-line maintenance effectiveness because of corrosion of packing bolts, insufficient packing, or aging of packing materials. If corroded valve bolts are replaced and sufficient new packing is added to existing valves during a turnaround, future on-line repair attempts will be greatly facilitated.

Various valve maintenance programs have been performed by EPA and refinery personnel. Union Oil Company and Shell Oil Company each conducted studies at their California refineries on maintenance of leaking valves. Emission rates were estimated based on screening value correlations.[6,7] EPA studied the effects of maintenance on fugitive emissions from valves at four refineries.[1] Each valve was sampled to determine emission rates before and after maintenance to evaluate emission reductions. In a separate study, EPA examined maintenance effectiveness on block valves at an ethylene production unit based on screening values alone.[8] In a subsequent study,[9] routine on-line maintenance achieved a 70 percent reduction in mass emissions.

In each of these studies, maintenance consisted of routine procedures, such as adjusting the packing gland while the valve was in service. In general, the programs concluded that (1) a reduction in emissions may be obtained by performing maintenance on valves with screening values above 10,000 ppmv; (2) for valves with screening values (before maintenance) below 10,000 ppmv, a slight reduction in emissions after maintenance may result; however, sometimes emissions from these valves may increase; and (3) directed maintenance (emissions measured during repair until VOC concentration drops to a specified level) is preferable to undirected maintenance (no measurement of the effect of repair). A detailed description of the testing programs and results is presented in Appendix C, Emission Source Test Data.

Valves that need to be repacked or replaced to reduce leakage must be isolated from the process. While control valves can usually be isolated, block valves, which are used to isolate or by-pass process equipment, normally cannot be isolated. One refiner estimates that 10 percent of the block valves can be isolated.[10]

When leaking valves can be corrected on-line, repair servicing can be done immediately after detection of the leak. When the leaks can be corrected only by a total or partial shutdown, the temporary emissions could be larger than the continuous emissions that would result from not shutting down the unit until it was time for a shutdown for other reasons. Simple maintenance procedures, such as packing gland tightening and grease injection, can be applied to reduce emissions from leaking valves until a shutdown is scheduled. Leaks that cannot be repaired on-line can be repaired by drilling into the valve housing and injecting a sealing compound. This practice is growing in acceptance, especially for safety concerns.[11]

4.2.2.3 Flanges. One refinery field study noted that most flange leaks could be sealed effectively on-line by simply tightening the flange bolts.[5] For a flange leak that requires off-line gasket seal replacement, a total or partial shutdown of the unit would probably be required because most flanges cannot be isolated.

For many of these cases, there are temporary flange repair methods that can be used. Unless a leak is major and cannot be temporarily corrected, the temporary emission from shutting down a unit would probably be larger than the continuous emissions that would result from not shutting down the unit until time for a shutdown for other reasons.

4.2.2.4 Compressors. Leaks from compressor seals may be reduced by the same repair procedure that was described for pumps (i.e., tightening the packing). Other types of seals, however, require that the compressor be taken out of service for repair. Since most compressors do not have spares, seal replacement necessitates a partial or complete unit shutdown. The shutdown for repair and the subsequent start-up can result in greater emissions than the emissions from the seal if it were allowed to leak until the next scheduled shutdown.

4.2.3 Emission Control Effectiveness of Leak Detection and Repair

The control efficiency achieved by a leak detection and repair program is dependent on several factors, including the leak definition, inspection interval, and the allowable repair time.

4.2.3.1 Definition of a Leak. The first step in developing a monitoring plan for fugitive VOC emissions is to define an instrument meter reading that is indicative of an equipment leak. The choice of the meter reading for defining a leak is influenced by several considerations. The percent of total mass emissions that can potentially be controlled by the leak detection and repair program can be affected by varying the leak definition. Table 4-2 gives the percent of total mass emissions predicted to be affected at various leak definitions

Table 4-2. PERCENT OF TOTAL MASS EMISSIONS AFFECTED AT VARIOUS LEAK DEFINITIONS[1]

Source Type	Percent of Mass Emissions Affected at This Leak Definition[a]			
	100,000 ppmv	50,000 ppmv	10,000 ppmv	1,000 ppmv
Pump Seals				
Light Liquid[b]	62	73	92	98
Heavy Liquid[c]	0	0	37	85
Valves				
Gas[d]	89	95	98	99
Light Liquid[b]	53	65	86	98
Heavy Liquid[c]	0	0	0	35
Safety/Relief Valves (Gas)[d]	30	47	74	95
Compressor Seals	48	66	91	98
Flanges	0	0	0	57

[a] These figures relate the leak definition to the percentage of total mass emissions that can be expected from sources with concentrations at the source greater than the leak definition. If these sources were instantaneously repaired to a zero leak rate and no new leaks occurred, then emissions could be expected to be reduced by this maximum theoretical efficiency.

[b] Light liquid is defined as a petroleum liquid with a vapor pressure greater than the vapor pressure of kerosene.

[c] Heavy liquid is defined as a petroleum liquid with a vapor pressure equal to or less than that of kerosene.

[d] Equipment in gas service contain process fluid in the gaseous state.

for a number of equipment types. From the table, it can be seen that, in general, a low meter reading leak definition results in larger potential emission reductions. The monitoring instruments presently in use for fugitive emission surveys have a maximum meter reading of 10,000 ppm. Add-on dilution devices are available to extend the range of the meter beyond 10,000 ppm, but these dilution probes are inaccurate and impractical for fugitive emissions monitoring surveys. Other considerations are more source specific.

For valves, the selection of an action level for defining a leak is a tradeoff between the desire to locate all significant leaks and to ensure that emission reductions are possible through maintenance. Although test data show that some few valves with meter readings less than 10,000 ppm have significant emission rates, most of the major emitters have meter readings greater than 10,000 ppm. Information obtained through EPA in-house testing and industry testing[12,13] indicates that in actual fugitive emission surveys, most sources of VOC have meter readings which are very low or very high. Maintenance programs on valves have shown that emission reductions are possible through on-line repair for essentially all valves with non-zero meter readings. There are, however, cases where on-line repair attempts result in an increased emission rate. The increased emissions from such a source could be greater than the emission reduction if maintenance is attempted on low leak valves. These valves should, however, be able to achieve essentially 100 percent emission reduction through off-line repair because the leaking valves can either be repacked or replaced. The emission rates from valves with meter readings greater than or equal to 10,000 ppm are significant enough so that an overall emission reduction will occur for a leak detection and repair program with a 10,000 ppm leak definition.

For pump and compressor seals, selection of an action level is different because the cause of leakage is different. As opposed to valves which generally have zero leakage, most seals leak to a certain extent while operating normally. The routine leakage is generally low, so these seals would tend to have low instrument meter readings. With time, however, as the seal begins to wear, the concentration and emission rate are likely to increase. At any time, catastrophic seal failure can occur with a large increase in the instrument meter reading and emission rate. As shown in Table 4-2, slightly over 90 percent of the emissions from pump and compressor seals are from sources with instrument meter readings greater than or equal to 10,000 ppm. Properly designed, installed, and operated seals have low instrument meter readings, and the bulk of the pump and compressor seal emissions are from seals that have worn out or failed such that they have a concentration equal to or greater than 10,000 ppm.

4.2.3.2 Inspection Interval. The length of time between inspections should depend on the expected occurrence and recurrence of leaks after a piece of equipment has been checked and/or repaired. This interval can be related to the type of equipment and service conditions, and different intervals can be specified for different pieces of equipment. Monitoring may be scheduled on an annual, quarterly, monthly, or weekly basis. Monitoring may also be scheduled for a "skip period" approach.

A skip-period schedule would allow less frequent monitoring for units that achieve a specified level of performance over a number of consecutive periods. For example, a unit that achieves less than 2 percent of its valves leaking for five consecutive quarterly monitoring periods might use an annual monitoring schedule as long as the percentage of its valves leaking does not exceed 2 percent. The skip-period approach allows flexibility for units that do not require regular monitoring to maintain good performance.

In the refinery VOC leak Control Technique Guideline (CTG) document,[4] the recommended leak detection intervals are as follows: annual -- pump seals and pipeline valves in liquid service; quarterly -- compressor seals, pipeline valves in gas service, and safety/relief valves in gas service; weekly -- visual inspection of pump seals; and no individual monitoring -- pipeline flanges and other connections, and safety/relief valves in liquid service. The choice of the interval affects the emission reduction achievable, since more frequent inspection will result in earlier detection and repair of leaking sources.

4.2.3.3 Allowable Repair Time. If a leak is detected, the equipment should be repaired within a certain time period. The allowable repair time should reflect an interest in reducing emissions, but it should also allow the plant operator sufficient time to obtain necessary repair parts and maintain some degree of flexibility in overall plant maintenance scheduling. The determination of this allowable repair time will affect emission reductions by influencing the length of time that leaking sources are allowed to continue to emit VOCs.

4.2.3.4 Estimation of Reduction Efficiency. Data are presented in Table 4-2 that show the expected fraction of total emissions from each type of source contributed by those sources with VOC concentrations greater than given leak definitions. If a leak detection and repair program resulted in repair of all such sources to 0 ppmv, elimination of all sources over the leak definition between inspections, and instantaneous repair of those sources found at each inspection, then emissions could be expected to be reduced by the amount reported in Table 4-2. However, since these conditions are not met in practice, the fraction of emissions from sources with VOC concentrations over the leak definition represents the theoretical maximum reduction efficiency. The approach to estimation of emission reduction presented here is to reduce this theoretical maximum control efficiency by accounting quantitatively for those factors outlined above.

This approach can be expressed mathematically by the following equation:[14]

$$\text{Reduction efficiency} = A \times B \times C \times D$$

Where:

A = Theoretical Maximum Control Efficiency = fraction of total mass emissions from sources with VOC concentrations greater than the leak definition (from Table 4-2).

B = Leak Occurrence and Recurrence Correction Factor = correction factor to account for sources which start to leak between inspections (occurrence), for sources which are found to be leaking, are repaired and start to leak again before the next inspection (recurrence), and for known leaks that could not be repaired.

C = Non-Instantaneous Repair Correction Factor = correction factor to account for emissions which occur between detection of a leak and subsequent repair, since repair is not instantaneous.

D = Imperfect Repair Correction Factor = correction factor to account for the fact that some sources which are repaired are not reduced to zero. For computational purposes, all sources which are repaired are assumed to be reduced to an emission level equivalent to a concentration of 1,000 ppmv.

As an example of this technique, Table 4-3 gives values for the "B," "C" and "D" correction factors for various possible inspection intervals, allowable repair times, and leak definitions.

An alternative to the ABCD correction factor model that may be used to determine leak detection and repair program effectiveness is an empirical approach which utilizes recently available data on leak occurrence, leak recurrence, and effectiveness of simple in-line repair (LDAR model). Estimates of leak detection and repair program effectiveness based on LDAR model results are presented in Appendix F.

4.3 PREVENTIVE PROGRAMS

An alternative approach to controlling fugitive VOC emissions from refinery operations is to replace components with leakless equipment. This approach is referred to as a preventive program. This section will discuss the kinds of equipment that could be applied in such a program and the advantages and disadvantages of this equipment.

4.3.1 Pumps

As discussed in Chapter 3, pumps can be potential fugitive VOC emission sources because of leakage through the drive-shaft sealing mechanism. This kind of leakage can be reduced to a negligible level through the installation of improved shaft sealing mechanisms, such as dual mechanical seals, or it can be eliminated entirely by installing sealless pumps.

4.3.1.1 Dual Mechanical Seals. As discussed in Chapter 3, dual mechanical seals consist of two mechanical sealing elements usually arranged in either a back-to-back or a tandem configuration. In both configurations a (nonpolluting) barrier fluid circulates between the seals. The barrier fluid system may be a circulating system, or it may rely on

Table 4-3. EMISSION CORRECTION FACTORS FOR VARIOUS INSPECTION INTERVALS, ALLOWABLE REPAIR TIMES, AND LEAK DEFINITIONS[a] (Reference 14)

Source	Leak Occurrence and Recurrence Correction Factor[b]			Non-Instantaneous Repair Correction Factor[c]			Imperfect Repair Correction Factor[d]			
	Inspection Interval			Allowable Repair Time (Days)			Leak Definition (ppmv)			
	Yearly	Quarterly	Monthly	15	5	1	100,000	50,000	10,000	1,000
Pump Seals										
Light Liquid[e]	0.800	0.900	0.950	0.979	0.993	0.999	0.974	0.972	0.941	0.886
Valves										
Gas[f]	0.800	0.900	0.950	0.979	0.993	0.999	0.998	0.998	0.996	0.992
Light Liquid[e]	0.800	0.900	0.950	0.979	0.993	0.999	0.988	0.980	0.958	0.916
Safety/Relief Valves[g]	0.800	0.900	0.950	0.979	0.993	0.999	0.995	0.993	0.985	0.968
Compressor Seals	0.800	0.900	0.950	0.979	0.993	0.999	0.994	0.992	0.984	0.972

[a] Note that these correction factors taken individually do not correspond exactly to the overall emission reduction obtainable by a monitoring and maintenance program. The overall effectiveness of the program is determined by the product of all correction factors.

[b] Values are assumed and account for sources that start to leak between inspections (occurrence), for sources that are found to be leaking, are repaired, and start to leak again before the next inspection (recurrence), and for leaking sources that could not be repaired.

[c] Accounts for emissions that occur between detection of a leak and subsequent repair.

[d] Accounts for the fact that some sources that are repaired are not reduced to zero. The average repair factors at 1,000 ppmv are assumed.

[e] Light liquid is defined as a petroleum liquid with a vapor pressure greater than that of kerosene.

[f] Valves in gas service carry process fluids in the gaseous state.

[g] Gas service only.

convection to circulate fluid within the system. While the barrier fluid's main function is to keep the pumped fluid away from the environment, it can serve other functions as well. A barrier fluid can provide temperature control in the stuffing box. It can also protect the pump seals from atmosphere, as in the case of pumping easily oxidizable materials which form abrasive oxides or polymers upon exposure to air. A wide variety of fluids can be used as barrier fluids. Some of the more common ones which have been used are water (or steam), glycols, methanol, oil, and heat transfer fluid. In cases in which product contamination cannot be tolerated, it may also be possible to use clean product, a product additive, or a product diluent.

Emissions of VOC from barrier fluid degassing vents can be controlled by a closed vent system, (discussed further in Section 4.3.5), which consists of piping and, if necessary, flow inducing devices to transport the degassing emissions to a control device, such as a process heater, or vapor recovery system. Control effectiveness of a dual mechanical seal and closed vent system is dependent on the effectiveness of the control device used and the frequency of seal failure. Failure of both the inner and outer seals can result in relatively large VOC emissions at the seal area of the pump. Pressure monitoring of the barrier fluid may be used in order to detect failure of the seals.[2] In addition, visual inspection of the seal area also can be effective for detecting failure of the outer seals. Upon seal failure, the leaking pump would have to be shut down for repair.

Dual mechanical seals are used in many refinery process applications; however, there are some conditions that preclude the use of dual mechanical seals. Their maximum service temperature is usually limited to less than 260°C, and mechanical seals cannot be used on pumps with reciprocating shaft motion.[2]

4.3.1.2 Sealless Pumps. The sealless or canned-motor pump is designed so that the pump casing and rotor housing are interconnected. As shown in Figure 4-1, the impeller, motor rotor, and bearings are completely enclosed and all seals are eliminated. A small portion of process fluid is pumped through the bearings and rotor to provide lubrication and cooling.

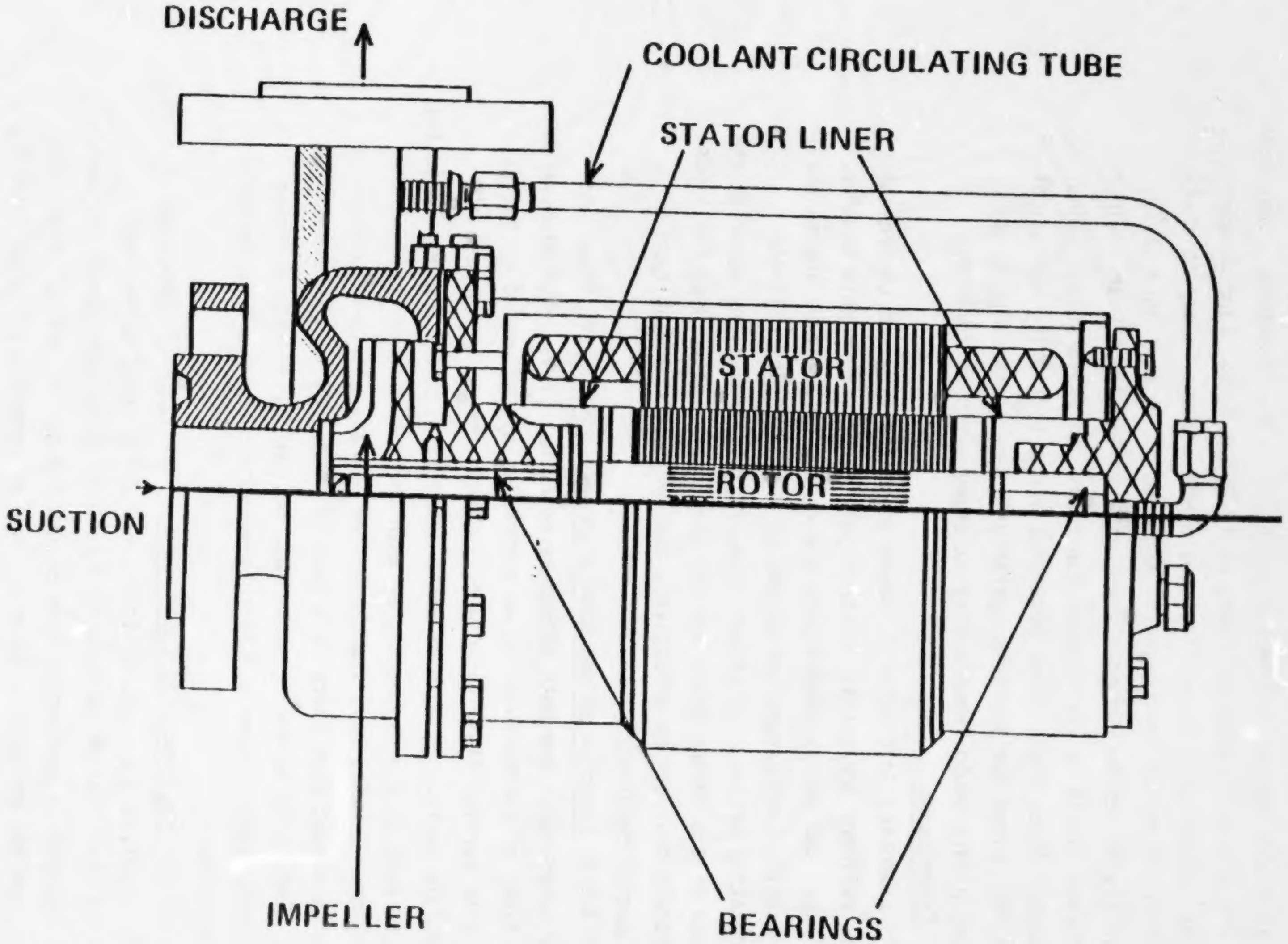
DISCHARGE
COOLANT CIRCULATING TUBE
STATOR LINER
STATOR
ROTOR
SUCTION
IMPELLER
BEARINGS

Figure 4-1. Seal-less Canned Motor Pump

Standard single-stage canned-motor pumps are available for flows up to 160 cubic meters per second and heads up to 76 meters. Two-stage units are also available for heads up to 183 meters. Canned-motor pumps are widely used in applications where leakage is a problem.[15]

The main design limitation of these pumps is that only clean process fluids may be pumped without excessive bearing wear. Since the process liquid is the bearing lubricant, abrasive solids cannot be tolerated. Also, there is no potential for retrofitting mechanical or packed seal pumps for sealless operation. Use of these pumps in existing plants would require that existing pumps be replaced.

4.3.2 Compressors

As discussed in Chapter 3, there are three types of compressors used in refinery processes: centrifugal, rotary, and reciprocating. Centrifugal and rotary compressors are driven by rotating shafts while reciprocating compressors are driven by shafts having a linear reciprocating motion. In either case, fugitive emissions occur at the junction of the moving shaft and the stationary casing, but the kinds of controls that can be effectively applied depend on the type of shaft motion involved.

4.3.2.1 Centrifugal and Rotary Compressors. Centrifugal and rotary compressors are both driven by rotating shafts. Emissions from these types of compressors can be controlled by the use of mechanical seals with barrier fluid (liquid or gas) systems or by the use of liquid film seals. In both of these types of seals, a fluid is injected into the seal at a pressure higher than the internal pressure of the compressor. In this way, leakage of the process gas to atmosphere is prevented except when there is a seal failure. As in the case of pumps, seal fluid degassing vents must be controlled with a closed vent system (see Section 4.3.5) to prevent process gas from escaping from the vent.

4.3.2.2 Reciprocating Compressors. This type of compressor usually involves a piston, cylinder, and drive-shaft arrangement. Since the shaft motion is linear, a packing gland arrangement is normally employed to prevent leakage around the moving shaft. This type of seal can be improved by inserting one or more spacer rings into the packing and connecting the void area or areas thus produced to a collection system through vents in the housing. This is referred to as a "scavenger" system. As with other fugitive emission collection systems, these vents must be controlled to prevent fugitive emissions from entering the atmosphere.

4.3.2.3 Seal Area Enclosures. There may be some compressors to which the above controls may not be applied. In these situations the seal area may be enclosed and the captured fugitive emissions routed to a control device by a closed vent system.

4.3.3. Valves

As in the case of pumps, valves can be sources of fugitive VOC emissions because of leakage through the packing used to isolate process fluids from atmosphere (see Chapter 3). This source of emissions, however, can be eliminated by isolating the valve stem from the process fluid. Sealed bellows valves are designed to perform in this manner.

The basic design of a sealed bellows valve appears in Figure 4-2. The stem in this type of valve is isolated from the process fluid by metal bellows. The bellows is generally welded to the bonnet and dish of the valve, thereby isolating the stem.

There are two main disadvantages to these valves. First, they are only available in globe and gate valve configurations. Second, the crevices of the bellows may be subject to corrosion under severe conditions if the bellows alloy is not carefully selected.

The main advantage of these valves is that they can be designed to withstand high temperatures and pressures so that leak-free service can be provided at operating conditions beyond the limits of diaphragm valves.

4.3.4 Safety/Relief Valves

As discussed in Chapter 3, safety/relief values can be sources of fugitive VOC emissions because of leakage through the valve seat. This type of leakage can be prevented by installing a rupture disk upstream of the valve, by connecting the discharge port of the valve to a closed-vent system, or by use of soft seat technology such as elastomer "O-rings." A rupture disk can be used upstream of a safety/relief valve so that under normal conditions it seals the

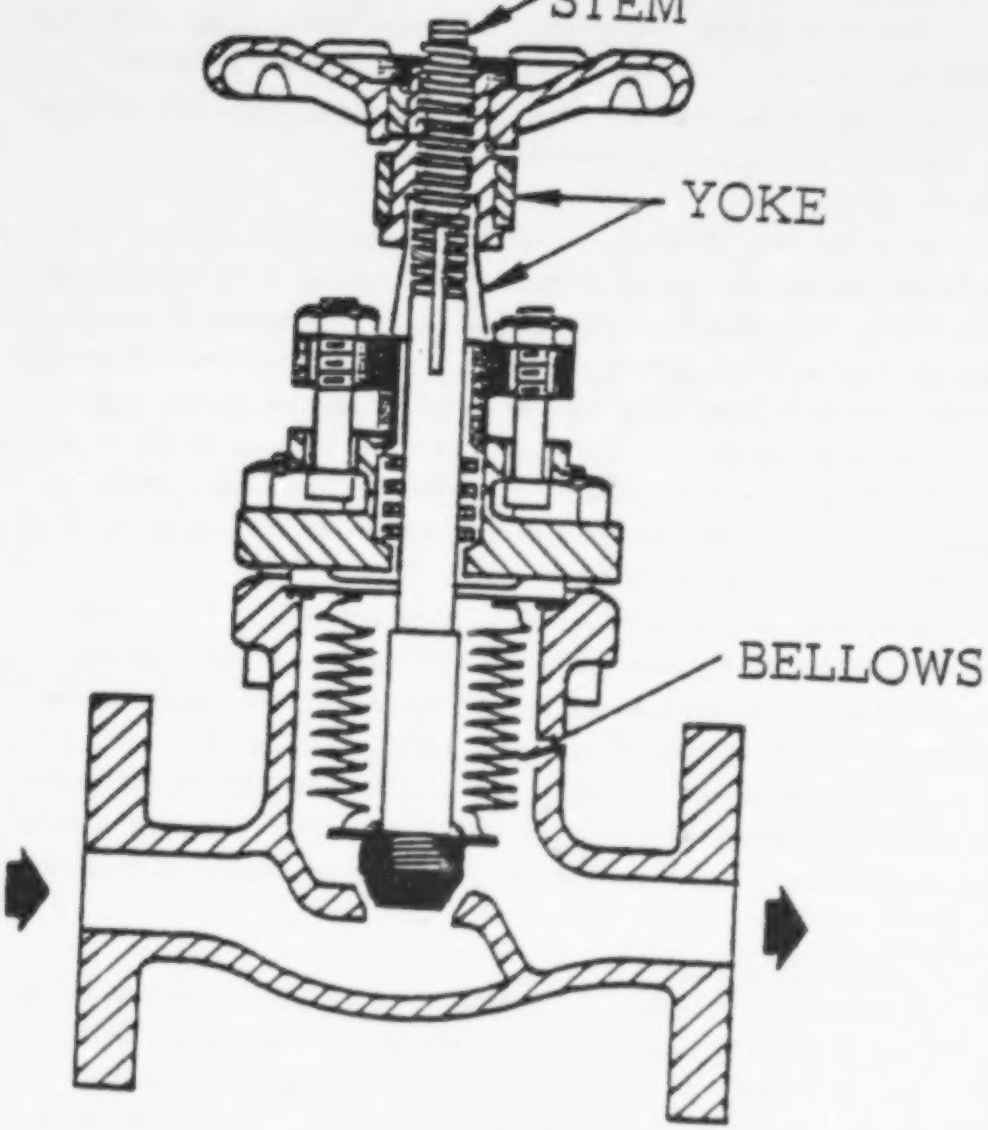
STEM
YOKE
BELLOWS

Figure 4-2. Sealed Bellows Valve

system tightly but will break when its set pressure is exceeded, at which time the safety/relief valve will relieve the pressure. Figure 4-3 is a diagram of a rupture disk and safety/relief valve installation. The installation is arranged to prevent disk fragments from lodging in the valve and preventing the valve from being reseated if the disk ruptures. It is important that no pressure be allowed to build in the pocket between the disk and the safety/relief valve; otherwise, the disk will not function properly. A pressure gauge and bleed valve can be used to prevent pressure buildup. With the use of a pressure gauge, it can be determined whether the disk is properly sealing the system against leaks.

It may be necessary to install a 2-port valve and parallel relief valve when using a rupture disk upstream of a relief valve. Such a system may be required to isolate the relief valve/rupture disk system for repair in case of an overpressure discharge. The parallel system would provide a backup relief valve during repair. However, a block valve upstream of the rupture disk/relief valve system will accomplish the same purpose where safety codes allow the use of a block valve for this purpose.

An alternative method for controlling relief valve emissions due to improper reseating is the use of a soft elastomer seat in the valve. An elastomer "o-ring" can be installed so that the valve always forms a tight seal after an overpressure discharge. However, this approach will not prevent leakage due to "simmering" as described in Chapter 3.

4.3.5 Closed-Vent Systems and Control Devices

A closed-vent system can be used to collect and dispose of gaseous VOC emissions resulting from seal oil degassing vents, pump and compressor seal leakage, relief valve leakage, and relief valve discharges due to overpressure operation. As mentioned in Section 4.3.1.1, a closed vent system consists of piping connectors, flame arrestors, and where needed, flow inducing devices. To obtain maximum emission reduction closed vent systems should be designed and operated such that all VOC emissions are transported to a control device without leakage to the atmosphere.

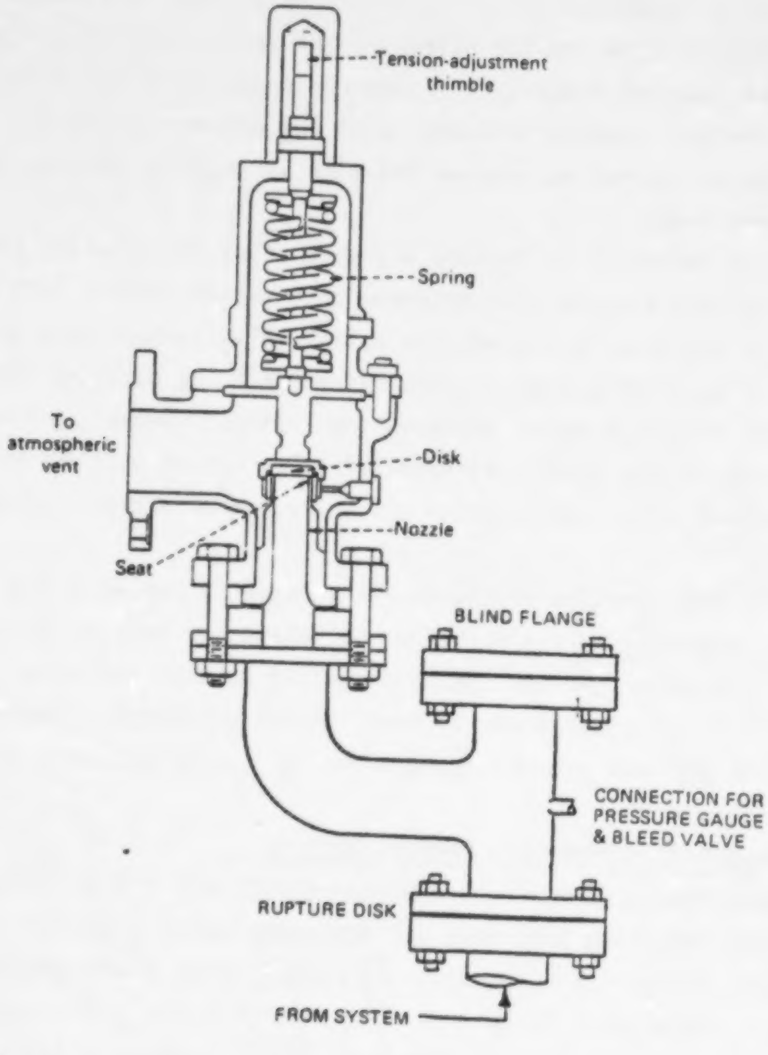
Tension-adjustment thimble
Spring
To atmospheric vent
Disk
Nozzle
Seat
BLIND FLANGE
CONNECTION FOR PRESSURE GAUGE & BLEED VALVE
RUPTURE DISK
FROM SYSTEM

Figure 4-3. Rupture Disk Installation Upstream of a Relief Valve[2]

Control devices which can be utilized in a closed vent system include process heaters and boilers, carbon adsorption units, refrigeration units, and gas recovery compressors. The efficiency of the system will be controlled by the efficiency of the control device. Emission measurements that reflect the effectiveness of these control devices in reducing VOC that are captured and transported to the devices by closed vent systems are limited. Without elaborate and costly materials balancing of VOC entering control devices, it is not practicable to measure the emissions from these control devices. However, efficiencies of greater than 90 percent may be provided by any of the above mentioned devices.[16,17]

Flares are used in the petroleum refining industry as a means of handling large emergency releases from process units and for combusting continuous, low flows of VOC that are transported by closed vent systems. A number of studies have contributed to the current state of knowledge of flare flames. However, the VOC emission reduction efficiency of flares used in refineries is uncertain because measurement methodologies have not been completely developed. Four flare studies provide information on flare gas composition, flow rate, and destruction efficiency. These flare studies present flare destruction efficiencies ranging from 91 to 100 percent for perfectly maintained, modern flares burning easily combusted gases.[18-21]

The best available flare design or state-of-the-art flare design is the smokeless flare. A smokeless flare is desirable because any smoke produced during flaring of VOC contains particulate, carbon monoxide, and unburned or partially oxidized VOC. The smokeless flare minimizes the amount of particulate, carbon monoxide, and VOC emitted by injecting steam or air into the VOC stream that is present in the flare header. The injection of steam or air increases the mixing of gases within the flare zone thereby increasing destruction of the VOC.

There are a number of engineering practices currently in use which help flares achieve smokeless operation. One system involves the use of staged elevated flare systems, where a small diameter flare is operated in tandem with a large diameter flare. The staged elevated flare system, shown in Figure 4-4, is designed such that the small flare takes the continuous low flow releases (such as seal oil degassing

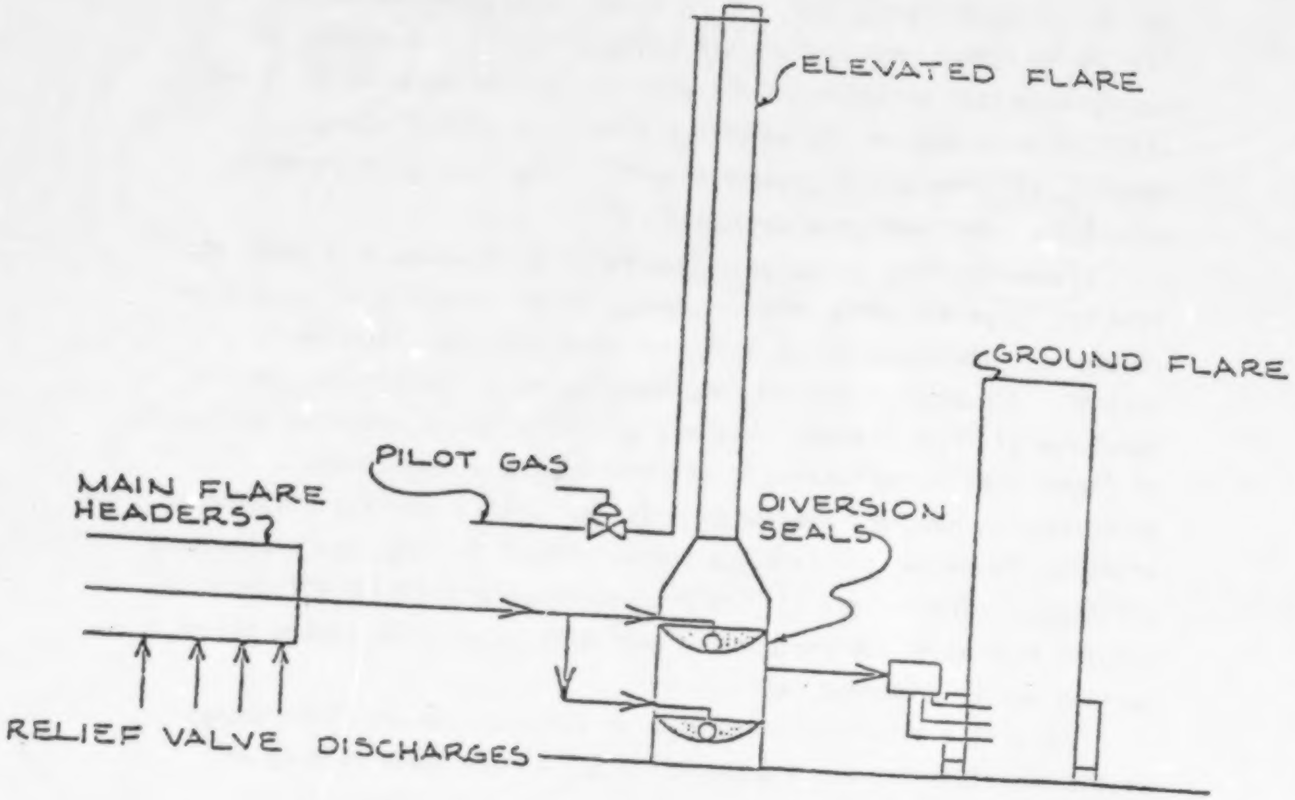
ELEVATED FLARE
GROUND FLARE
PILOT GAS
MAIN FLARE HEADERS
DIVERSION SEALS
RELIEF VALVE DISCHARGES

Figure 4-4. Simplified Closed-Vent System with Dual Flares[2]

vents) and the larger flare accepts large intermittent flows (such as relief valve discharges). A second system involves the use of a small, separate line to the flare tip for continuous low volume, low pressure releases. The small conveyance line is used in order to maintain higher exit velocities of gases entering the flare head, thereby aiding combustion of the low flow VOC stream. A third system, sometimes used in conjunction with either of the above systems involves the use of flare gas recovery. In the third system, a compressor is used to recover the continuously generated flare gas "base load." The compressor is sized to handle the "base load," and any excess gas is flared.

4.3.6 Open-Ended Lines

Caps, plugs, and double block and bleed valves are devices for closing off open-ended lines. When installed downstream of an open-ended line, they are effective in preventing leaks through the seat of the valve from reaching atmosphere. In the double block and bleed system, it is important that the upstream valve be closed first. Otherwise, product will remain in the line between the valves, and expansion of this product can cause leakage through the valve stem seals.

The control efficiency will depend on such factors as frequency of valve use, valve seat leakage, and material that may be trapped in the pocket between the valve and cap or plug and lost on removal of the cap or plug. Annual emissions from a leaking open-ended valve are approximately 100 kg.[22] Assuming that open-ended lines are used an average of 10 times per year, that 0.1 kg of trapped organic material is released when the valve is used, and that all of the trapped organics released are emitted to atmosphere, the annual emissions from closed off open-ended lines would be 1 kg. This would be a 99 percent reductions in emissions. Due to the conservative nature of these assumptions, a 100 percent control efficiency has been to estimate the emission reductions of closing off open-ended lines.

4.3.7 Closed-Purge Sampling

VOC emissions from purging sampling lines can be controlled by a closed-purge sampling system, which is designed so that the purged VOC is returned to the system or sent to a closed disposal system in order that the handling losses are minimized. Figure 4-5 gives two examples

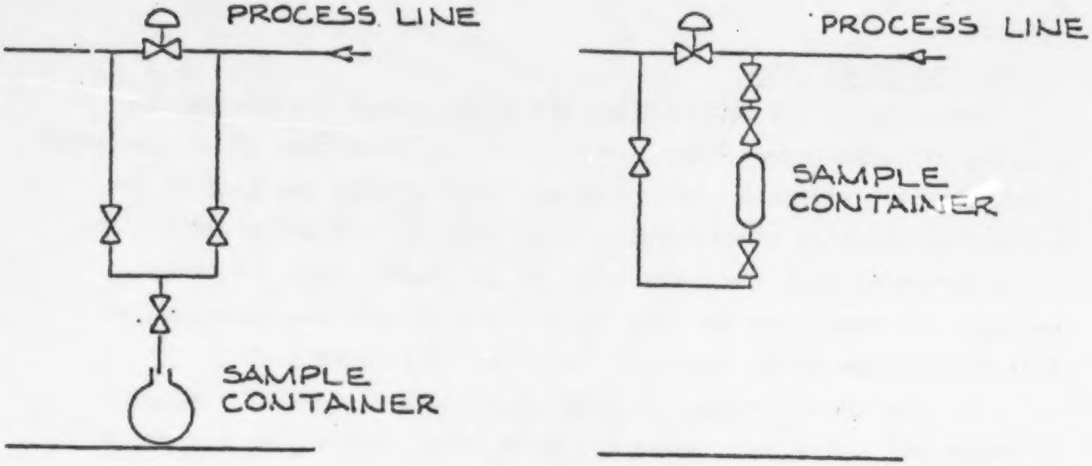
PROCESS LINE
SAMPLE CONTAINER
PROCESS LINE
SAMPLE CONTAINER

Figure 4-5. Diagram of Two Closed-Loop Sampling Systems[2]

of closed-purge sampling systems where the purged VOC is flushed from a point of higher pressure to one of lower pressure in the system and where sample-line dead space is minimized. Other sampling systems are available that utilize partially evacuated sampling containers and require no line pressure drop.[23] For emission calculations, it has been assumed that closed-purge sampling systems will provide 100 percent control efficiency for the sample purge.

4.3.8 Cooling Towers

In a recent survey, the majority of cooling towers tested did not have significant VOC emissions. These cooling towers use indirect (non-contact) condensation which is expected to be used in all future applications. Presently there are no known techniques to reduce the VOC emissions from indirect condensation cooling towers beyond the level of control presently found in the industry. Direct contact condensation is used in some existing refineries, but its use is being phased out due to environmental considerations.

4.3.9 Process Drains and Wastewater Separators

There are several known techniques for reducing VOC emissions from process drains and wastewater separators. Process drain emissions can be controlled by reducing the amount of VOC that is spilled or otherwise put into the drain system. The drains can also be controlled by installing inverted U-bends to trap VOC within the drain system. Available data show that only a small percentage of drains have concentrations greater than 10,000 ppmv.[1] Wastewater separators can be controlled by covering or enclosing the only water surface of the separator. Although uncontrolled wastewater separator emissions can be quite large,[24] the results of ongoing studies[25] will need to be reviewed to determine the magnitude of emissions under existing controls. If the emissions from process drains or wastewater separators are found to be significant, these sources will be addressed in future regulations.

4.3.10 Blowdown Systems

As stated in Chapter 3, a typical process unit turnaround with vessel blowdown includes pumping the liquid contents to a storage facility, depressurizing the vessel to remove vapors, flushing any remaining vapors, and then ventilating the vessel before the workmen enter. Industry practice and existing State and local regulations provide venting of hydrocarbons and purge gases to flares or vapor recovery systems to the extent that the overall impact of a turnaround on fugitive emissions is probably no longer significant.[26]

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5.0 MODIFICATION AND RECONSTRUCTION

In accordance with the provisions of Title 40 of the Code of Federal Regulation (CFR), Sections 60.14 and 60.15, an existing facility can become an affected facility and, consequently, subject to the standards of performance if it is modified or reconstructed. An "existing facility," defined in 40 CFR 60.2, is a facility of the type for which a standard of performance is promulgated and the construction or modification of which was commenced prior to the proposal date of the applicable standards. The following discussion examines the applicability of modification/reconstruction provisions to petroleum refinery operations that involve fugitive VOC emissions.

5.1 GENERAL DISCUSSION OF MODIFICATION AND RECONSTRUCTION PROVISIONS

5.1.1 Modification

Modification is defined in Section 60.14 as any physical or operational change to an existing facility which results in an increase in the emission rate of the pollutant(s) to which the standard applies. Paragraph (e) of Section 60.14 lists exceptions to this definition which will not be considered modifications, irrespective of any changes in the emission rate. These changes include:

1. Routine maintenance, repair, and replacement;
2. An increase in the production rate not requiring a capital expenditure as defined in Section 60.2(bb);
3. An increase in the hours of operation;
4. Use of an alternative fuel or raw material if, prior to the standard, the existing facility was designed to accommodate that alternative fuel or raw material;
5. The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission

control system is removed or replaced by a system considered to be less environmentally beneficial.

As stated in paragraph (b), emission factors, material balances, continuous monitoring systems, and manual emission tests are to be used to determine emission rates expressed as kg/hr of pollutant. Paragraph (c) affirms that the addition of an affected facility to a stationary source through any mechanism -- new construction, modification, or reconstruction -- does not make any other facility within the stationary source subject to standards of performance. Paragraph (f) provides for superseding any conflicting provisions. And, (g) stipulates that compliance be achieved within 180 days of the completion of any modification.

5.1.2 Reconstruction

Under the provisions of Section 60.15, an existing facility becomes an affected facility upon reconstruction, irrespective of any change in emission rate. A source is identified for consideration as a reconstructed source when: (1) the fixed capital costs of the new components exceed 50 percent of the fixed capital costs that would be required to construct a comparable entirely new facility, and (2) it is technologically and economically feasible to meet the applicable standards set forth in this part. The final judgment on whether a replacement constitutes reconstruction will be made by the Administrator of EPA. As stated in Section 60.15(f), the Administrator's determination of reconstruction will be based on:

> (1) The fixed capital cost that would be required to construct a comparable new facility; (2) the estimated life of the facility after the replacements compared to the life of a comparable entirely new facility; (3) the extent to which the components being replaced cause or contribute to the emissions from the facility; and (4) any economic or technical limitations in compliance with applicable standards of performance which are inherent in the proposed replacements.

The purpose of the reconstruction provision is to ensure that an owner or operator does not perpetuate an existing facility by replacing all but minor components, support structures, frames, housing, etc., rather than totally replacing it in order to avoid being subject to applicable performance standards. In accordance with Section 60.5, EPA will, upon request, determine if an action taken constitutes construction (including reconstruction).

5.2 APPLICABILITY OF MODIFICATION AND RECONSTRUCTION PROVISIONS TO REFINERY VOC FUGITIVE EMISSION SOURCES

Changes in refinery product demand and in available refinery feedstocks are expected to result in a number of modernization and alteration projects at existing refineries over the next several years. Some of these projects could result in existing units becoming subject to the provisions of Sections 60.14 and 60.15. Examples in which this could occur are presented below.

5.2.1 Modification

VOC fugitive emissions from existing refinery process units could increase in several ways. This might occur if the number of pumps and valves associated with the unit were increased. The number of pumps and valves associated with a process unit may be increased in order to increase its production rate or in order to increase downstream capacity because of the production increase of the unit.

This kind of process unit alteration is expected when increased production of light hydrocarbon products (e.g., gasoline, diesel, and jet fuel) occurs by increased processing of residual oils. Demand for residual oils is expected to decline steadily in the future due to increased competition from coal and natural gas. Therefore, it is desirable to convert residual oils to lighter, more profitable products.[1]

To upgrade residual oils, it is necessary to increase the ratio of hydrogen to carbon. Hydrogen may be added through a variety of commercially available hydroprocessing units or carbon may be removed through traditional carbon rejection operations such as delayed coking or thermal cracking. The products of these operations may be further processed by catalytic cracking to produce light hydrocarbons for gasoline, jet fuel, or diesel.[1]

It is expected that a number of residual oil conversion projects will be undertaken by existing refineries in the near future to increase production of more desirable light hydrocarbon products. These conversion projects could increase VOC fugitive emission rates by the addition of fugitive emission sources to existing process units.

Routine changes and additions of fugitive emission sources are commonly made to increase ease of maintenance, to increase productivity, to improve plant safety, and to correct minor design flaws. These additions of fugitive emission sources may cause an increase in fugitive emissions. However, fugitive emissions from other sources could be reduced to compensate for this increase.

5.2.2 Reconstruction

An existing refinery process unit may replace a number of unit components during modernization or process alteration projects. This could occur if an existing crude distillation unit that is designed to process low sulfur, light crude oil is converted to accommodate high sulfur, heavy crude oil. Many of the unit's fugitive emission sources (pumps, valves, etc.) would have to be replaced in order to withstand the more corrosive conditions caused by the change in feedstocks. It is possible that the cost of converting the unit could exceed 50 percent of the cost of a new unit.

The replacement of several fugitive emission sources at an existing process unit might also be considered a reconstruction. For example, if several pumps, compressors, and sampling loops were replaced at an existing gas processing plant, the fixed capital cost of the new equipment might exceed 50 percent of the cost of a new unit.

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*References can be located in Docket Number A-80-44 at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

6.0 MODEL UNITS AND REGULATORY ALTERNATIVES

6.1 INTRODUCTION

This chapter presents model unit parameters and regulatory alternatives for reducing VOC fugitive emissions from petroleum refining facilities. The model units consist of three groupings of process equipment that are representative of the range of process complexity present in the petroleum refining industry. They provide a basis for comparing the environmental and economic impacts of the regulatory alternatives. The regulatory alternatives consist of various combinations of the available control techniques and provide incremental levels of emission control.

6.2 MODEL UNITS

Emission testing data from petroleum refineries indicate that VOC fugitive emission rates are dependent on the number of pieces of equipment (pumps, valves, etc.) present in a process unit and not dependent on equipment throughput, age, temperature, or pressure.[1] For this reason, model units were developed based on process unit equipment populations. Refinery process units of similar complexity (equipment populations) were categorized into the three model units as discussed below.

6.2.1 Derivation of Model Units

In the development of new source standards, model plants are normally used to assess the impacts of the regulatory alternatives. Since process emissions are generally porportional to plant production rates, model plants are usually defined in terms of production rates or throughputs for a given process. However, the majority of VOC fugitive emissions originate from leaks in process equipment such as pumps, valves, and compressors. Thus, in order to assess the impacts of the regulatory alternatives on VOC fugitive emissions, it is necessary to develop model units based on the number of pieces of equipment utilized in various refinery process units.

In developing the model units, the array of petroleum refining processes was first condensed into 12 basic operations as follows: crude distillation, vacuum distillation, thermal cracking, catalytic cracking, hydrotreating, isomerization, alkylation, hydrogen production, reforming, solvent extraction, lube oil production, and asphalt units. Next, average equipment inventories for each type of unit were derived.[2,3,4] Unit equipment counts consider only those components operating in less than 10 percent benzene service. Components servicing greater than 10 percent benzene streams are covered by the proposed national emission standard for benzene fugitive emissions.

The equipment counts for existing units were weighted with respect to projected unit growth for the period from 1982 to 1986 (growth projections are discussed in Appendix E). Thus, the unit component counts reflect the range of source populations that are expected in refinery units during implementation of standards of performance.

The weighted average unit equipment inventories revealed three groups of refining processes of similar complexity. These three categories represent the model units discussed in Section 6.2.2.

6.2.2 Model Unit Parameters

Model Unit A characterizes an equipment inventory characteristic of the least complex production units within a petroleum refinery. The individual process units reflected in Model Unit A include hydrotreating, isomerization, lube oil, asphalt, and hydrogen production. Model Unit B represents alkylation, thermal cracking, reforming, vacuum distillation, and solvent extraction. Model Unit C, the most complex process unit, is representative of crude distillation (including a saturated gas plant) and catalytic cracking (including an unsaturated gas plant). The technical parameters for the model units are shown in Table 6-1.

The model unit components are further categorized according to the nature of the process streams they handle. This distinction is made because emission rates increase with increasing vapor pressure (volatility) of the process stream. Hence, valves are subdivided into three categories: (1) gas/vapor service (valves in gas or vapor

TABLE 6-1. MODEL UNIT COMPONENT COUNTS

Source	Service	Model[a] Unit A	Model[b] Unit B	Model[c] Unit C
Valves	Gas/Vapor[d]	130	260	780
	Light Liquid[e]	250	500	1,500
	Heavy Liquid[f]	150	300	900
Open-Ended Lines[g] (Purge, drain, sample lines)	All	70	140	420
Sampling Connections	All	10	20	60
Pump Seals	Light Liquid[e]	7	14	40
	Heavy Liquid[f]	3	6	20
Flanges	All	1,900	3,800	11,000
Pressure Relief Devices	Gas/Vapor[d]	3	7	20
Compressor Seals	All	1	3	8

[a] Model Unit A represents hydrotreating, isomerization, lube oil, asphalt blowing, and hydrogen.

[b] Model Unit B represents alkylation, thermal cracking, solvent extraction, reforming, and vacuum distillation.

[c] Model Unit C represents crude distillation and fluid catalytic cracking.

[d] Components in gas/vapor service at process conditions.

[e] Light liquid is defined as a fluid with a vapor pressure greater than 0.3 kPa at 20°C. This vapor pressure represents the split between kerosene and naphtha.

[f] Heavy liquid is defined as a fluid with a vapor pressure less than or equal to 0.3 kPa at 20°C. This vapor pressure represents the split between kerosene and naphtha.

[g] Ratio: 7 open-ended lines to 1 pump seal. Reference 5.

service at process conditions); (2) light liquid service (streams with a vapor pressure greater than kerosene, greater than 0.3 kPa at 20°C); and (3) heavy liquid service (streams with a vapor pressure equal to or less than kerosene, or less than or equal to 0.3 kPa at 20°C). Pump seals similarly distinguish between light and heavy liquid service.

6.3 REGULATORY ALTERNATIVES

This section presents six regulatory alternatives for controlling fugitive VOC emissions from petroleum refineries. The alternatives define feasible programs for achieving varying levels of emission reduction. The first alternative represents a "status quo" of fugitive emission control in which case the impact analysis is based on no additional controls. The remaining regulatory alternatives require increasingly restrictive controls comprised of the techniques discussed in Chapter 4. Table 6-2 summarizes the requirements of the regulatory alternatives.

6.3.1 Regulatory Alternative I

Regulatory Alternative I reflects normal existing plant operations with no additional regulatory requirements. This baseline regulatory alternative provides the basis for incremental comparison of the impacts of the other regulatory alternatives. While refineries in some States may be subject to some fugitive VOC emission controls through prevention of significant deterioration (PSD) regulations, SIP regulations, and other permitting requirements, the existing levels of control would not be expected to have a significant national impact. An uncontrolled baseline has, therefore, been assumed for model process units.

6.3.2 Regulatory Alternative II

Regulatory Alternative II provides a higher level of emission control than the baseline alternative through leak detection and repair methods as well as equipment specifications. The requirements of this alternative are based upon the recommendations of the refinery VOC leak control techniques guideline (CTG) document.[5]

The alternative specifically entails yearly monitoring for valves in light liquid service and pump seals in light liquid service.

Table 6-2. FUGITIVE VOC REGULATORY ALTERNATIVE CONTROL SPECIFICATIONS

	Regulatory Alternatives[a]									
	II[b]		III		IV		V		VI	
Source	Inspection Interval	Equipment Specification	Inspection Interval	Equipment Specification	Inspection Interval	Equipment Specification	Inspection Interval	Equipment Specification	Inspection Interval	Equipment Specification
Valves										
Gas/Vapor	Quarterly	None	Quarterly	None	Quarterly	None	Monthly	None	None	Sealed Bellows Valve
Light Liquid	Yearly	None	Quarterly	None	Quarterly	None	Monthly	None	None	Sealed Bellows Valve
Open-ended Lines (purge, drain, sample lines)	None	Cap	None	Cap	None	Cap	None	Cap	None	Cap
Sampling Connections	None	None	None	Closed-purge sampling	None	Closed-purge sampling	None	Closed-purge sampling	None	Closed-purge sampling
Pump Seals										
Light Liquid	Yearly[c]	None	Monthly[c]	None	None[c]	Dual Mechanical Seals Controlled Degassing Vents	None	Dual Mechanical Seals[d] Controlled Degassing Vents	None	Dual Mechanical Seals[d] Controlled Degassing Vents
Relief Valves	Quarterly	None	None	Rupture Disks	None	Rupture Disks	None	Rupture Disks	None	Rupture Disks
Compressor Seals	Quarterly[e]	None	None	Controlled Degasing Vents	None	Controlled Degassing Vents	None	Controlled Degassing Vents	None	Controlled Degassing Vents

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[a] Regulatory Alternative I (baseline) includes no new regulatory specifications and, hence, is not included in this table.

[b] Alternative II is equivalent to controls recommended in the refinery CTG for fugitive VOC emissions.

[c] For pumps, instrument monitoring would be supplemented with weekly visual inspections for liquid leakage. If liquid is noted to be leaking from the pump seal, the pump seal will be repaired.

[d] A pressure sensing device should be installed between the dual mechanical seals and should be monitored to detect seal failure.

[e] Quarterly monitoring and repair is not generally an effective control technique for all compressors. In some instances, compressor repair may necessitate a process unit turnaround because compressors generally are not spared.

Quarterly monitoring for leaks from valves, pressure relief devices, and compressors in gas/vapor service is required. Pump seals would additionally receive weekly visual inspection. Visual detection of a leak would direct that monitoring be initiated. Subsequently, any leaks found in excess of a predetermined VOC concentration would require repair. Finally, caps would be installed on open-ended lines including purge, drain, and sample lines.

6.3.3 Regulatory Alternative III

Regulatory Alternative III provides more restrictive emission control than Regulatory Alternative II by increasing the frequency of equipment inspections and by specifying additional equipment requirements. By increasing the monitoring intervals, emissions are reduced from residual leaking sources (i.e., those that are found leaking and are repaired and recur before the next inspection, and those sources that begin leaking between inspections). In Regulatory Alternative III, the inspection interval for light liquid valves and light liquid pump seals are increased to a quarterly and monthly basis, respectively. Leak monitoring is replaced by installation of rupture disks for safety/relief valves and by mechanical contact seals with controlled degassing reservoirs for compressors. Closed purge sampling systems are also required. Other requirements are the same as for Alternative II.

6.3.4 Regulatory Alternative IV

The incremental emission reduction offered in Regulatory Alternative IV is achieved by installing dual mechanical seals with a barrier fluid system and degassing reservoir vents on light liquid pumps. Subsequently, monthly monitoring for pumps is no longer required. Other controls remain as in Regulatory Alternative III.

6.3.5 Regulatory Alternative V

Regulatory Alternative V increases emission control by requiring more frequent inspections on gas/vapor and light liquid valves. Valve monitoring is required on a monthly basis. All other specifications remain as in Regulatory Alternative IV.

6.3.6 Regulatory Alternative VI

Regulatory Alternative VI offers the highest level of emission reduction of the regulatory alternatives. This regulatory alternative controls fugitive VOC emissions through stringent equipment specifications.

Alternative VI employs the equipment specifications required in Alternative V with the addition of sealed bellows valves on gas/vapor and light liquid service valves.

6.4 REFERENCES

1. Wetherhold, R.G., C.P. Provost, and C.D. Smith. Assessment of Atmospheric Emissions from Petroleum Refining. Volume 3. Appendix B. EPA-600/2-80-075c. April 1980. Docket Reference Number II-A-19.*

2. Powell, et al. Development of Petroleum Refinery Plot Plans. Pacific Environmental Services, Inc. EPA-450/3-78-025. June 1978. Docket Reference Number II-A-7.*

3. Wetherhold, R.G., and D.D. Rosebrook. Assessment of Atmospheric Emissions from Petroleum Refining. Volume 1. Technical Report. EPA-600/2-80-075a. April 1980. Docket Reference Number II-A-17.*

4. The 1978 Refining Handbook Issue. Hydrocarbon Processing. 57(9):99. September 1978. Docket Reference Number II-I-32.*

5. Control of Volatile Organic Compound Leaks from Petroleum Refinery Equipment. EPA-450/2-78-036, OAQPS No. 1.2-111. June 1978. Docket Reference Number II-A-6.*

*References can be located in Docket Number A-80-44 at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

7.0 ENVIRONMENTAL IMPACTS

7.1 INTRODUCTION

This chapter discusses the environmental impacts of implementing the regulatory alternatives presented in Chapter 6. The primary emphasis is on the quantitative assessment of fugitive VOC emissions that would result from implementation of each regulatory alternative. The impacts of the regulatory alternatives on water quality, solid waste, energy, and other environmental concerns are also addressed in this chapter.

The environmental impacts presented in this chapter are based on emission reductions calculated using the ABCD model discussed in Section 4.2.3.4. An alternative approach used to estimate the environmental impacts of each regulatory alternative (the LDAR model) is based on leak occurrence/leak recurrence data and data on the effectiveness of simple in-line repair. Environmental impacts based on LDAR model results are presented in Tables F-14 through F-18.

7.2 VOC EMISSIONS IMPACT

7.2.1 Emission Source Characterization

As discussed in Chapter 6, the model units consist of several types of process equipment (for example, valves and pumps) that comprise the major fugitive VOC emission sources within petroleum refineries. The emission factors presented in Table 3-1 are characteristic of existing conditions in refineries. These emission factors represent "uncontrolled" emissions and are used to estimate VOC emissions under Regulatory Alternative I. Regulatory Alternative II represents emission reductions achieved through the use of control technology and leak detection/repair programs delineated in Control of Volatile Organic Compound Leaks from Petroleum Refining Equipment (CTG).[1] Regulatory Alternatives III through VI represent progressive increments of the control technology and leak detection/repair programs discussed in Chapter 4.0. A baseline emissions level is used to evaluate the emission reduction potentials of Regulatory Alternatives II through VI on affected model units nationwide. The baseline VOC emission levels are calculated as the weighted average emissions of refineries operating in National Ambient Air Quality Standard (NAAQS) for ozone attainment areas (no controls) and refineries operating in NAAQS for ozone nonattainment areas (CTG controls).[2]

7.2.2 Development of VOC Emission Levels

In order to estimate the impacts of the regulatory alternatives on fugitive VOC emission levels, emission factors for the model units are determined for each regulatory alternative. Controlled VOC emission factors are developed for those sources that would be subject to a leak detection and repair program. Controlled VOC emission factors are calculated by multiplying the uncontrolled emission factor for each type of equipment by a set of correction factors (see Chapter 4). The correction factors account for imperfect repair, noninstantaneous repair, and the occurrence or recurrence of leaks between leak detection inspections. Where the regulatory alternatives specify equipment to be used, it is assumed that there are no emissions from the controlled source. The resulting controlled VOC emission factors appear in Table 7-1.

Table 7-2 presents fugitive VOC emissions by source type for each model unit under Regulatory Alternatives I through VI; the percent of total emissions attributable to each source type is also presented. Table 7-3 compares annual VOC emissions from model units operating under Regulatory Alternatives II through VI to emissions from model units operating under Regulatory Alternative I. Average emission reductions from Regulatory Alternative I (uncontrolled) levels for model units operating under Regulatory Alternatives II through VI are 69, 78, 80, 83, and 93 percent, respectively.

7.2.3 Future Impact on Fugitive VOC Emissions

Future impacts of the regulatory alternatives on fugitive refinery VOC emissions are estimated for the 5-year period, 1982 to 1986, as shown in Table 7-4. Future impacts of the regulatory alternatives are determined as the product of the number of affected model units projected

Table 7-1. CONTROLLED VOC EMISSION FACTORS FOR VARIOUS INSPECTION INTERVALS[a]

Source type	Inspection interval	Uncontrolled emission factor[b] (kg/day)	Correction factors				Control efficiency (AxBxCxD)	Controlled emission factor[g] (kg/day)
			A[c]	B[d]	C[e]	D[f]		
Valves								
Gas/vapor	Quarterly[h,i,j]	0.64	0.98	0.90	0.98	1.0	0.86	0.090
	Monthly[j]		0.98	0.95	0.98	1.0	0.91	0.058
Light liquid	Annually[h]	0.26	0.86	0.80	0.98	0.96	0.65	0.091
	Quarterly[i,j]		0.86	0.90	0.98	0.96	0.73	0.071
	Monthly[k]		0.86	0.95	0.98	0.96	0.77	0.060
Pump Seals								
Light liquid	Annually[h]	2.7	0.92	0.80	0.98	0.94	0.68	0.86
	Monthly[i]		0.92	0.95	0.98	0.94	0.80	0.54
Relief valves								
Gas/vapor	Quarterly[h]	3.9	0.74	0.90	0.98	0.98	0.64	1.4
Compressor Seals	Quarterly[h]	15.0	0.91	0.90	0.98	0.98	0.79	3.2

[a] Values presented in this table are analogous to LDAR model values presented in Table F-14.

[b] From Table 3-1. Reference 1.

[c] Theoretical maximum control efficiency — From Table 4-2.

[d] Leak occurrence and recurrence correction factor — assumed to be 0.80 for yearly inspection, 0.90 for quarterly inspection and 0.95 for monthly inspection.

[e] Noninstantaneous repair correction factor — for a 15-day maximum allowable repair time, assuming a 7.5 day — average repair time yields a 0.98 yearly correction factor: [365 - (15/2)] ÷ 365 = 0.98.

[f] Imperfect repair correction factor — from Table 4-3, calculated as 1- (f÷F), where f = average emission rate for sources at 1000 ppm and F = average emission rate for sources greater than 10,000 ppm.

[g] Controlled emission factor = uncontrolled emission factor x [1-(AxBxCxD)]

[h] Required in Regulatory Alternative II.

[i] Required in Regulatory Alternative III.

[j] Required in Regulatory Alternative IV.

[k] Required in Regulatory Alternative V.

Table 7-2. VOC EMISSIONS FOR REGULATORY ALTERNATIVES[a]

	Regulatory Alternatives											
	I		II		III		IV		V		VI	
Source type	Uncontrolled emissions[b] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total
Valves												
gas/vapor	83	38	12	18	12	24	12	26	7.5	20	0	0
light liquid	65	30	23	34	18	36	18	39	15	39	0	0
heavy liquid	0.80	1	0.80	1	0.80	2	0.80	2	0.80	2	0.80	5
Open-Ended Lines	3.9	2	0	0	0	0	0	0	0	0	0	0
Sampling connections	3.6	2	3.6	5	0	0	0	0	0	0	0	0
Pump Seals												
light liquid	19	9	6.0	9	3.8	8	0	0	0	0	0	0
heavy liquid	2.0	1	2.0	3	2.0	4	2.0	4	2.0	5	2.0	13
Flanges	13	6	13	19	13	26	13	28	13	34	13	82
Relief Valves gas/vapor	12	5	4.2	6	0	0	0	0	0	0	0	0
Compressor Seals	15	7	3.2	5	0	0	0	0	0	0	0	0
Total	220		68		50		46		38		16	

[a] Values presented in this table are analogous to LDAR model values presented in Table F-15.

[b] Uncontrolled emissions are obtained by multiplying the uncontrolled emission factors for each source (Table 3-1) by their respective model unit component counts (Table 6-1).

[c] Controlled emissions for Regulatory Alternatives II through VI are obtained by multiplying the controlled emission factors for each source (Table 7-1) by their respective model unit component counts (Table 6-1).

Table 7-2. VOC EMISSIONS FOR REGULATORY ALTERNATIVES (Continued)[a]

	Regulatory Alternatives											
	I		II		III		IV		V		VI	
Source type	Uncontrolled emissions[b] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total
Valves												
gas/vapor	170	37	23	16	23	23	23	26	15	19	0	0
light liquid	130	28	46	33	35	36	35	39	30	39	0	0
heavy liquid	2	1	2	1	2	2	2	2	2	3	2	6
Open-Ended Lines	7	2	0	0	0	0	0	0	0	0	0	0
Sampling connections	7.2	2	7.2	5	0	0	0	0	0	0	0	0
Pump Seals												
light liquid	38	8	12	9	7.6	8	0	0	0	0	0	0
heavy liquid	3	1	3	2	3	3	3	3	3	4	3	9
Flanges	27	6	27	19	27	28	27	30	27	35	27	84
Relief Valves gas/vapor	27	6	9.8	7	0	0	0	0	0	0	0	0
Compressor Seals	45	10	9.6	7	0	0	0	0	0	0	0	0
Total	460		140		98		90		77		32	

[a] Values presented in this table are analogous to LDAR model values presented in Table F-15.

[b] Uncontrolled emissions are obtained by multiplying the uncontrolled emission factors for each source (Table 3-1) by their respective model unit component counts (Table 6-1).

[c] Controlled emissions for Regulatory Alternatives II through VI are obtained by multiplying the controlled emission factors for each source (Table 7-1) by their respective model unit component counts (Table 6-1).

Table 7-2. VOC EMISSIONS FOR REGULATORY ALTERNATIVE (Concluded)[a]

	Regulatory Alternatives											
	I		II		III		IV		V		VI	
Source type	Uncontrolled emissions[b] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total
Valves												
gas/vapor	500	38	70	17	70	24	70	26	45	18	0	0
light liquid	390	29	140	34	105	36	105	39	90	36	0	0
heavy liquid	4	1	4	1	4	1	4	1	4	2	4	4
Open-Ended Lines	20	2	0	0	0	0	0	0	0	0	0	0
Sampling connections	22	2	22	5	0	0	0	0	0	0	0	0
Pump Seals												
light liquid	110	8	34	8	22	8	0	0	0	0	0	0
heavy liquid	10	1	10	2	10	3	10	4	10	4	10	11
Flanges	77	6	77	19	77	27	77	29	77	31	77	85
Relief Valves gas/vapor	78	6	28	7	0	0	0	0	0	0	0	0
Compressor Seals	120	9	26	6	0	0	0	0	0	0	0	0
Total	1330		410		290		270		250		91	

[a] Values presented in this table are analogous to LDAR model values presented in Table F-15.

[b] Uncontrolled emissions are obtained by multiplying the uncontrolled emission factors for each source (Table 3-1) by their respective model unit component counts (Table 6-1).

[c] Controlled emissions for Regulatory Alternatives II through VI are obtained by multiplying the controlled emission factors for each source (Table 7-1) by their respective model unit component counts (Table 6-1).

Table 7-3. ANNUAL MODEL UNIT EMISSIONS AND AVERAGE PERCENT EMISSION REDUCTION FROM REGULATORY ALTERNATIVE I[a]

Regulatory Alternative	Model unit emissions (Mg/year)[b]			Average percent emission reduction	
	A	B	C	From Regulatory Alternative I	Incremental
I[c]	80	170	485	--	--
II	25	51	150	69	69
III	18	36	110	78	28
IV	17	33	99	80	8
V	14	28	91	83	14
VI	6	12	33	93	59

[a] Values presented in this table are analogous to LDAR model values presented in Table F-16.

[b] From Table 7-2. Based on 365 days per year.

[c] Regulatory Alternative I represents "uncontrolled" emissions.

Table 7-4. PROJECTED VOC FUGITIVE EMISSIONS FROM AFFECTED MODEL UNITS FOR REGULATORY ALTERNATIVES FOR 1982-1986[a]

		Number of affected model units[b]			Total fugitive emissions projected under regulatory alternative (Gg/yr)[c]						
	Year	A	B	C	I	Base Line[d]	II	III	IV	V	VI
New Units	1982	9	5	4	3.5	2.2	1.1	0.8	0.7	0.6	0.2
	1983	19	10	9	7.6	4.5	2.1	1.7	1.5	1.4	0.5
	1984	29	15	14	11.7	7.2	3.6	2.6	2.4	2.1	0.8
	1985	39	21	19	15.9	9.7	4.9	3.5	3.2	2.9	1.1
	1986	49	27	24	20.1	12.3	6.2	4.5	4.1	3.6	1.4
Modified/ Reconstructed Units	1982	9	15	11	8.6	5.2	2.6	1.9	1.7	1.5	0.6
	1983	18	31	22	17.4	10.6	5.3	3.9	3.5	3.1	1.2
	1984	27	47	33	26.1	16.0	8.0	5.8	5.3	4.7	1.8
	1985	37	67	44	35.7	21.8	10.9	7.9	7.2	6.4	2.5
	1986	47	79	56	44.3	27.1	13.6	9.9	9.0	8.0	3.1

[a] Values presented in this table are analogous to LDAR model values presented in Table F-17.

[b] The numbers of affected model units projected through 1986 are cumulative and distinguish between new unit construction and modification/reconstruction. Units in existence prior to 1982 are otherwise excluded. A discussion of the growth projections is in Appendix E.

[c] The total fugitive emissions from Model Units A, B, and C are derived from the emissions per model unit in Table 7-3. The sum of emissions in any one year is the sum of the products of the number of affected facilities per model unit times the emission per model unit.

[d] The baseline emission level is the weighted sum of the emissions in Regulatory Alternatives I (uncontrolled) and II (CTG controls) and is based on the proportion of refineries in nonattainment (169/302 = 56 percent) and attainment (133/302 = 44 percent) areas (Reference 2).

for each year (detailed in Appendix E) and the total quantity of fugitive emissions per model unit estimated for each of the regulatory alternatives (from Table 7-3).

Over the 5-year period, total fugitive VOC emissions for new units under baseline conditions are projected to be 40.2 gigagrams; baseline emissions from existing modified/reconstructed units may contribute an additional 90.3 gigagrams of fugitive VOC. Implementation of Regulatory Alternatives II through VI would reduce total new unit emissions over the 5-year period to 17.9, 13.1, 11.9, 10.6, and 4.0 gigagrams, respectively. For modified/reconstructed units, Regulatory Alternatives II through VI are expected to reduce fugitive VOC emissions for the 5-year period to 40.4, 29.4, 26.7, 23.7, and 9.2 gigagrams, respectively. Over the 5-year period, percent emission reductions from the baseline level for new and modified/ reconstructed units under Regulatory Alternatives II through VI are 55, 67, 70, 74, and 90 percent, respectively.

7.3. WATER QUALITY IMPACT

Although fugitive VOC emissions from refinery equipment primarily impact air quality, they also adversely impact water quality. In particular, leaking components handling liquid hydrocarbon streams increase the waste load entering wastewater treatment systems. Leaks from equipment contribute to the waste load by entering process unit drains via run-off. Implementation of Regulatory Alternatives II through VI would reduce the waste load on wastewater treatment systems by preventing leakage from process equipment from entering the wastewater system.

7.4 SOLID WASTE IMPACT

Solid wastes that are generated by the petroleum refining industry and that are associated with the regulatory alternatives include replaced mechanical seals, seal packing, rupture disks, and valves. Sources of solid waste not related to the regulatory alternatives include separator and tank sludges, filter cakes, treating clays, and slop oil.

Implementation of Regulatory Alternatives II through VI would increase solid waste quantities whenever equipment specifications require the replacement of existing equipment. For example, dual mechanical seals would replace packed and single mechanical seals under Alternatives IV, V, and VI.

Implementation of Alternatives II through VI would not have a significant impact beyond baseline solid waste levels. Solid waste impacts of the regulatory alternatives can be minimized by recycling metal solid wastes (for example, mechanical seals, rupture disks, caps, plugs, and valve parts). Further, most refinery solid waste is unrelated to the regulatory alternatives.

7.5 ENERGY IMPACTS

The regulatory alternatives would require a minimal increase in energy consumption because of the operation of monitoring instruments, the operation of degassing vents, the use of closed loop sampling, and the operation of combustion devices. However, implementation of Regulatory Alternatives II through VI would result in a net positive energy impact, as energy savings from the "recovered" VOC emissions far outweigh the energy requirements of the alternatives.

The average energy value of the "recovered" emissions is estimated at 49 terajoules per gigagram.[3] Assuming that all of the emission reduction achieved by the regulatory alternatives is recovered as usable energy, the energy savings over a 5-year period from new units is estimated to be from 1,090 terajoules (Regulatory Alternative II) to 1,770 terajoules (Regulatory Alternative VI). Energy savings by modified/ reconstructed units operating under Regulatory Alternatives II through VI represent an additional 2,450 to 3,970 terajoules, respectively. Energy impacts of each regulatory alternative are presented in Table 7-5; energy savings in crude oil equivalents are also presented.

7.6 OTHER ENVIRONMENTAL CONCERNS

7.6.1 Irreversible and Irretrievable Commitment of Resources

Implementation of the regulatory alternatives is not expected to result in any irreversible or irretrievable commitment of resources. Rather, implementation of Alternatives II through VI would save resources because of energy savings associated with reductions in fugitive VOC emissions. As previously noted, the generation of solid waste used in the control equipment would not be significant.

7.6.2 Environmental Impact of Delayed Regulatory Action

As discussed in the above sections, implementation of the regulatory alternatives would not significantly impact water quality or solid

TABLE 7-5. PROJECTED ENERGY IMPACTS OF REGULATORY ALTERNATIVES FOR 1982-1986[a]

	Regulatory Alternative	Five-year total reduction from baseline (Gg)[b]	Energy value of emission reduction (terajoules)[c]	Crude oil equivalent of emission reduction ($10^3 m^3$)[d]
New Units	II	18.0	882	23
	III	22.8	1,120	29
	IV	24.0	1,180	31
	V	25.3	1,240	32
	VI	31.9	1,560	41
Modified/ Reconstructed Units	II	40.3	1,970	51
	III	51.3	2,510	65
	IV	54.0	2,650	69
	V	57.0	2,790	72
	VI	71.5	3,500	91

[a] Values presented in this table are analogous to LDAR model values presented in Table F-18.

[b] Estimated total fugitive VOC emission reduction from Model Units A, B, and C, from Table 7-4.

[c] Based on 49 TJ/Gg, these values represent energy credits (Reference 4).

[d] Based on 38.5 TJ/Mm^3 (6.12×10^9 J/bbl) crude oil. Reference 5.

waste generation. However, a delay in regulatory action would adversely impact air quality at the rates shown in Table 7-4. The energy loss associated with delayed regulatory action represents less than 1 percent of annual crude oil imports for the industry.[6]

7.7 REFERENCES

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*References can be located in Docket Number A-80-44 at the U.S. Environmental Protection Agency Library, Waterside Mill, Washington, D.C.

8.0 COST ANALYSIS

8.1 COST ANALYSIS OF REGULATORY ALTERNATIVES

8.1.1 Introduction

The following sections present estimates of the captial costs, annualized costs, and cost-effectiveness for each model unit and regulatory alternative discussed in Chapter 6.0. These estimates are used to ascertain the economic impact of the regulatory alternatives upon the petroleum refining industry in Chapter 9.0. To ensure a common cost basis, Chemical Engineering cost indices are used to adjust control equipment to May 1980 dollars.

Annualized cost impacts and cost effectiveness values presented in this chapter are calculated using the ABCD model discussed in Section 4.2.3.4. An alternative approach used to estimate the annualized cost impact and cost effectiveness of each regulatory alternative (the LDAR model) is based on leak occurrence/leak recurrence data and data on the effectiveness of simple in-line repair. Cost impacts based on LDAR model results are presented in Tables F-12 through F-23.

8.1.2 New Facilities

8.1.2.1 Capital Costs. The bases for the capital costs of monitoring instruments and control equipment are presented in Table 8-1. These data are used to tabulate the capital costs for each model unit under the regulatory alternatives as given in Table 8-2. The capital cost figures used may be conservative. For example, one degassing system is assumed to serve every two dual mechanical pump seals; in normal practice, several pump seals may be tied to a single barrier fluid degassing reservoir. Further, the cost for the rupture disk system includes extra fittings (for example, tee and elbow,) and the cost of sealed bellows valves is for a 5.1 cm control valve, which costs considerably more than smaller bellows valves. Engineering

TABLE 8-1. INSTALLED CAPITAL COST DATA
(May 1980 Dollars)

Item	Installed Capital Cost	Cost Basis	Reference
1. Monitoring Instrument	$9,200/Model Unit	Cost is for two instruments, $4,600 each. Assumes one instrument is used as a spare.	1
2. Caps for Open-Ended Lines	$53 (new or retrofit)	Based on the cost of a[a] 2.5 cm screwed valve. Cost (1967) = $12. Cost index = 329.0/113. Installation = 1 hour at $18/hr.	2, 3, 4
3. Dual Mechanical Seals	$1,260 (new)	Seal cost = $1,250. Seal credit (last quarter 1978) = $225. Cost index = 328.9/266.6. Installation = 16 hours at $18/hr.	3, 4, 5, 6
	$1,592 (Retrofit)	Seal cost = $1,250. Field installation = 19 hours at $18/hr.	
4. Barrier Fluid System for Dual Mechanical Seals	$1,850 (new or retrofit)	Pressurized Reservoir system cost (January 1979) = $700. System cooler cost (January 1979) = 800. Cost index = 328.9/266.6.	3, 4, 7
5. Pump Seal Barrier Fluid Degassing Reservoir Vent	$4,000/pump seal (new or retrofit)	Based on installation of a 122 m length of 5.1 cm diameter schedule 40 carbon steel pipe at a cost of $6,400, plus three 5.1 cm cast steel plug valves and one metal gauge flame arrestor at a cost of $1,600. These costs include connection of the degassing reservoir to an existing enclosed combustion device or vapor recovery header. Cost of a control device added specifically to control the degassing vents is, therefore, not included. It is assumed that two pump seals are connected to a single degassing vent.	4, 5, 7
6. Compressor Degassing Reservoir Vents	$8,000/compressor seal (new or retrofit)	The costs have the same basis as pump seals with a single compressor seal connected to a vent.[b]	4, 5, 7

TABLE 8-1. INSTALLED CAPITAL COST DATA (Cont.)
(May 1980 Dollars)

Item	Installed Capital Cost	Cost Basis	Reference
7.1 Rupture Disk System With Block Valve	$2,000/Relief Valve (new)	Cost of rupture disk assembly: one 7.6 cm rupture disk stainless = $230; one 7.6 cm rupture disk holder, carbon steel = $384; one 0.6 cm pressure gauge, dial face = $18; one 0.6 cm bleed valve, carbon steel, gate = $30; and installation = 16 hrs at $18/hr. To allow in-service disk replacement, a block valve is assumed to be installed upstream of the rupture disk. Cost for one 7.6 cm gate valve = $700. Installation = 10 hrs at $18/hr. To prevent damage to the relief valve by disk fragments, an offset mounting is required. Cost for one 10.2 cm tee and one 10.2 cm elbow = $21. Installation = 8 hrs. at $18/hr.	3, 4, 5
	$3,636/Relief Valve (retrofit)	Costs for the rupture disk, holder, and block valve are the same as for the new applications. An additional cost is added to replace the derated relief valve. No credit is assumed for the used relief valve. Cost for one 7.6 cm pressure relief valve, stainless steel body and trim = $1,456. Installation = 10 hrs. at $18/hr.	
7.2 Rupture Disk System With 3-way Valve	$4,100/Relief Valve (new)	Costs for rupture disk assembly are the same as for new rupture disk system (above), except replace block valve with one 3-way valve (7.6 cm, 2-port) = $1320. Additional cost for one 7.6 cm pressure relief valve, stainless = $1456; Cost for two 7.6 cm elbows = $30. Total installation = 36 hrs. at $18/hr.	8
	$4,800/Relief Valve (retrofit)	Costs for rupture disk assembly and 3-way valve costs are the same as for new applications except total installation = 72 hrs at $18/hr.	

Table 8-1. INSTALLED CAPITAL COSTS DATA (Concluded)
(May 1980 Dollars)

Item	Installed Capital Cost	Cost Basis	Reference
8. Closed-loop Sampling Connections	$530 (new or retrofit)	Based on 6 m length of 2.5 cm diameter schedule 40, carbon steel pipe and three 2.5 cm carbon steel ball valves. Installation = 18 hrs. at $18/hr.	
9. Sealed Bellows Valves	$2,730 (new or retrofit)	Cost for 5.1 cm sealed bellows control valve.	4, 9

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[a] Lines larger than 2.5 cm may be controlled by installing blind flanges at similar cost.

[b] The compressor seal area could be vented directly to a control device at similar cost.

[c] Engineering codes will allow a single relief valve protected by rupture disk with block valve upstream. Some refineries may opt to install a parallel relief/valve and rupture disk system at nearly double the cost.

TABLE 8-2. INSTALLED CAPITAL COST ESTIMATES
FOR NEW MODEL UNITS
(Thousands of May 1980 Dollars)

Capital Cost Item	Regulatory Alternative				
	II	III	IV	V	VI
Model Unit A					
1. Monitoring Instrument	9.2	9.2	9.2	9.2	9.2
2. Caps for Open-Ended Lines	3.7	3.7	3.7	3.7	3.7
3. Dual Mechanical Seals					
● Seals			6.8	6.8	6.8
● Installation			2.0	2.0	2.0
4. Barrier Fluid System for Dual Mechanical Seals			13	13	13
5. Pump Seal Barrier Fluid Degassing Reservoir			28	28	28
6. Compressor Degassing Reservoir Vents		8	8	8	8
7. Rupture Disk System					
● Disks		0.69	0.69	0.69	0.69
● Assembly and Installation		8.5	8.5	8.5	8.5
8. Closed-loop Sampling Connections		5.3	5.3	5.3	5.3
9. Sealed Bellows Valves					1000
Total	13	35	85	85	1100

TABLE 8-2. INSTALLED CAPITAL COST ESTIMATES
FOR NEW MODEL UNITS (Continued)
(Thousands of May 1980 Dollars)

Capital Cost Item	Regulatory Alternative				
	II	III	IV	V	VI
Model Unit B					
1. Monitoring Instrument	9.2	9.2	9.2	9.2	9.2
2. Caps for Open-Ended Lines	7.4	7.4	7.4	7.4	7.4
3. Dual Mechanical Seals					
• Seals			14	14	14
• Installation			4.0	4.0	4.0
4. Barrier Fluid System for Dual Mechanical Seals			26	26	26
5. Pump Seal Barrier Fluid Degassing Reservoir			56	56	56
6. Compressor Degassing Reservoir Vents		24	24	24	24
7. Rupture Disk System					
• Disks		1.6	1.6	1.6	1.6
• Assembly and Installation		20	20	20	20
8. Closed-loop Sampling Connections		11	11	11	11
9. Sealed Bellows Valves					2100
Total	17	73	168	168	2300

TABLE 8-2. INSTALLED CAPITAL COST ESTIMATES FOR NEW MODEL UNITS (Concluded)
(Thousands of May 1980 Dollars)

Capital Cost Item	Regulatory Alternative				
	II	III	IV	V	VI
Model Unit C					
1. Monitoring Instrument	9.2	9.2	9.2	9.2	9.2
2. Caps for Open-Ended Lines	22	22	22	22	22
3. Dual Mechanical Seals					
• Seals			39	39	39
• Installation			12	12	12
4. Barrier Fluid System for Dual Mechanical Seals			74	74	74
5. Pump Seal Barrier Fluid Degassing Reservoir			160	160	160
6. Compressor Degassing Reservoir Vents		64	64	64	64
7. Rupture Disk System					
• Disks		4.6	4.6	4.6	4.6
• Assembly and Installation		56	56	56	56
8. Closed-loop Sampling Connections		32	32	32	32
9. Sealed Bellows Valves					6200
Total	31	190	470	470	6600

judgment indicates that refineries may use either block valves or 3-way valves to isolate ruptured discs from streams during disc replacement. When block valves are used, the process stream does not have a pressure relief valve outlet during periods when the pressure relief device is isolated for in-service replacement of the rupture discs. When 3-way valves are employed, the process stream is routed around the ruptured disc assembly to a pressure relief valve. To account for the use of block valves and 3-way valves in this cost analysis, it is assumed that 50 percent of the affected refineries employ block valves and the remainder use 3-way valves.

Regulatory Alternative I requires no additional controls and therefore, incurs no capital costs. Under Regulatory Alternatives II through VI, caps for open-ended lines and two monitoring instruments would be purchased. Although only one instrument is required, the cost of a second instrument is included, as it is assumed that refiners will use the second monitor in the event the first monitor becomes inoperable. There are no other capital costs associated with Alternative II. Regulatory Alternatives III, IV, V, and VI bear the added costs of controlled degassing reservoir vents for compressors, rupture disk system using block valves or 3-way valves, and closed-loop sampling connections. Regulatory Alternatives IV and V bear similar capital costs. In addition to the capital costs projected in Alternative III, Regulatory Alternatives IV and V incur the cost of dual mechanical seals, barrier fluid systems, and pump seal barrier fluid degassing reservoirs. Further, Regulatory Alternative VI capital costs include the costs of sealed bellows valves for valves in light liquid and gas/vapor service.

8.1.2.2 Annual Costs. Implementation of Regulatory Alternatives II through V would require visual and/or instrument monitoring of potential VOC emissions. The monitoring requirements are given in Table 6-2. Table 6-2 also shows that Regulatory Alternative VI requires equipment specifications rather than detection and repair of leaks from existing equipment. Table 8-3 summarizes the leak detection and repair labor requirements; Table 8-4 presents annual labor costs of leak detection and repair by model unit type for Regulatory Alternatives II through IV.

Table 8-3. MONITORING AND MAINTENANCE LABOR-HOUR REQUIREMENTS[a]

				LEAK DETECTION					LEAK REPAIR						
Source Type	Components Per Model Unit A	B	C	Type of Monitoring[b]	Times Monitored Per Year	Monitoring Labor-Hours Required[c,d] A	B	C	Percent of Sources Leaking[e]	Estimated Number of Leaks[f] A	B	C	Maintenance Labor-Hours[g] A	B	C
Valves															
Gas/Vapor	130	260	780	Instrument	4[h,i,j]	17	35	104	10	6	11	32	7	12	36
				Instrument	12[k]	52	104	312		8	16	47	9	18	53
light liquid	250	500	1500	Instrument	1[h]	8.3	17	50	11	6	11	33	7	12	37
				Instrument	4[i,j]	33	67	200		11	22	66	12	25	75
				Instrument	12[k]	100	200	600		17	33	99	19	37	112
Pump Seals															
light liquid	7	14	40	Instrument	1[h]	1.2	2.3	6.7	24	1	1	2	80	80	160
				Instrument	12[i]	14	28	80		1	2	6	80	160	480
				Visual	52[h,i,j,k,l]	3	6.1	17							
Relief Valves															
Gas/Vapor	3	7	20	Instrument	4[h]	3.2	7.5	21.3	7	0	0	0	0	0	0
Compressor Seals															
Gas/Vapor	1	3	8	Instrument	4[h]	1	2	5.3	35	1	1	1	40	40	40

NOTES:

[a] Values presented in this table are analogous to LDAR model values presented in Table F-19.

[b] Assumes that instrument monitoring requires a two-person team and visual monitoring one person.

[c] Monitoring time per person: pumps-instrument 5 min., visual 1/2 min.; compressors 5 min.; valves 1 min., and safety/relief valves 8 min. Reference 10.

[d] Monitoring labor-hours = number of workers x number of components x time to monitor x times monitored per year.

[e] Reference 11.

[f] Annual percent recurrence factors have been applied for monthly, quarterly, and annual instrument inspections. It is assumed that 5 percent of leaks initially detected are found with monthly monitoring (0.05 x 12 = 0.6), that 10 percent of leaks initially detected are found with quarterly monitoring (0.1 x 4 = 0.4), and that 20 percent of leaks initially detected are found by annual monitoring (0.2 x 1 = 0.2). Number of leaks = Number of Components x % Sources Leaking x Annual % Recurrence Factor.

[g] Leak Repair = Number of Leaks x Repair Time. Labor-Hours: Repair time per component: pumps - 80 hrs., compressors - 40 hrs., valves - 1.13 hrs. (Basis: weighted average on 75 percent of the leaks repaired on-line requiring 10 minutes per repair, and on 25 percent of the leaks repaired off-line requiring 4 hrs. per repair. Reference 12), safety relief valves - 0 hrs. (It is assumed that these leaks are corrected by routine maintenance at no additional labor requirement). Reference 10.

[h] Required in Regulatory Alternative II.

[i] Required in Regulatory Alternative III.

[j] Required in Regulatory Alternative IV.

[k] Required in Regulatory Alternative V.

[l] Required in Regulatory Alternative VI.

TABLE 8-4. LEAK DETECTION AND REPAIR COSTS[a,b]
(May 1980 Dollars)

Regulatory Alternatives[b]	Leak Detection Cost Model Units			Repair Cost Model Units		
	A	B	C	A	B	C
II	610	1,300	4,500	2,400	2,600	4,900
III	1,200	2,500	7,200	1,800	3,500	11,000
IV	1,000	1,900	5,800	340	670	2,000
V	2,800	5,600	17,000	500	990	3,000

[a] Values presented in this table are analogous to LDAR model values presented in Table F-20.

[b] Cost = Hours (From Table 8-3) x $18.00 per hour.

[c] Regulatory Alternatives I and VI have zero costs.

These repair costs cover the expense of repairing those components in which leaks develop after initial repair. The cost for leak detection and repair labor is assumed to be $18.00 per hour.[7]

Administrative and support costs are estimated at 40 percent of the sum of leak detection and repair labor costs.[7] Leak detection labor, leak repair labor, and administrative/support costs are recurring annual costs for each regulatory alternative.

8.1.2.3 Annualized Costs. The bases for deriving the annualized control costs are presented in Table 8-5. The annualized capital, maintenance, and miscellaneous costs are calculated by taking the appropriate factor from Table 8-5 and multiplying it by the corresponding capital cost from Table 8-2. The capital recovery factors (CRF) are calculated using the equation:

$$\mathrm{CRF} = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where i = interest rate, expressed as a decimal,

n = economic life of the component, years.

The interest rate used is 10 percent.[7] The expected life of the monitoring instrument is six years.[7] Dual mechanical seals and rupture disks are assumed to have a nominal 2-year life. All other control equipment is assumed to have a nominal 10-year life.

Implementation of Regulatory Alternative II, III, IV, or V results in an initial discovery of leaking components. The repair labor-hour requirements of the initial survey are derived by multiplying the percentage of sources leaking and the repair time per source by the model unit component counts as shown in Table 8-6. Fractions are rounded up to the next integer, since in practice it is the whole valve or seal that is replaced, not just part of one unit. The cost of repairing initial leaks is amortized over a 10-year period, since it is a one-time cost. Administrative and support costs to implement the regulatory alternatives are assumed to be 40 percent of the leak detection and repair labor costs. The initial leak repair costs presented in Table 8-7 show Alternative II to incur the highest costs. Costs for the other alternatives decrease as equipment specifications replace labor intensive equipment repairs.

TABLE 8-5. DERIVATION OF ANNUALIZED LABOR, ADMINISTRATIVE, MAINTENANCE, AND CAPITAL COSTS

1. Capital Recovery factor for Capital Costs	
• Dual mechanical seals and rupture disks	0.58 x Capital[a]
• Other control equipment	0.163 x Capital[b]
• Monitoring instruments	0.23 x Capital[c]
2. Annual Maintenance Costs	
• Control equipment	0.05 x Capital[d]
• Monitoring instruments	$3,000[e]
3. Annual Miscellaneous Costs	0.04 x Capital[f]
4. Labor Costs	$18/hr[g]
5. Administrative and Support Costs to Implement Regulatory Alternative	0.40 x (Monitoring Labor + Maintenance Labor)[h]
6. Annualized Charge for Initial Leak Repairs	(estimated number of leaking components per model unit[i] x repair time) x $18/hr[h] x 1.4 x 0.163[j]

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[a] Applies to cost of seals ($972-incremental cost due to specification of dual seals instead of single seals) and disk ($230) only. Two year life, ten percent interest.

[b] Ten year life, ten percent interest. Reference 7.

[c] Six year life, ten percent interest. Reference 7.

[d] Reference 7.

[e] Includes materials and labor for maintenance and calibration.

[f] Reference 3.

[g] Includes wages plus 40 percent for labor-related administrative and overhead costs.

[h] Reference 7.

[i] Shown in Table 8-3.

[j] Initial leak repair amortized for ten years at ten percent interest.

Table 8-6. LABOR-HOUR REQUIREMENTS FOR INITIAL LEAK REPAIR

Source Type	Number of Compenents Per Model Unit			Percent of Sources Leaking in Initial Survey[a]	Estimated Number of Leaks			Repair Time Per Source[b] (hours)	Repair Labor-Hours		
	A	B	C		A	B	C		A	B	C
Valves											
Gas/Vapor[c,d,e,f]	130	260	780	10	13	26	78	1.13	15	29	88
light liquid[c,d,e,f]	250	500	1,500	11	28	55	165	1.13	32	62	186
Pump Seals											
light liquid[c,d]	7	14	40	24	2	3	10	80	160	240	800
Safety/Relief Valves											
Gas/Vapor[c]	3	7	20	7	1	1	2	0[g]	0	0	0
Compressor Seals											
Gas/Vapor[c]	1	3	8	35	1	1	3	40	40	40	120

[a] Based on the number of sources leaking at ≥10,000 ppm from Table 4-3. Reference 11.

[b] From Table 8-3.

[c] Required in Regulatory Alternative II.

[d] Required in Regulatory Alternative III.

[e] Required in Regulatory Alternative IV.

[f] Required in Regulatory Alternative V.

[g] Because of safety requirements, it is assumed that leaks are corrected by routine maintenance and therefore require no additional labor. Reference 10.

TABLE 8-7. INITIAL LEAK REPAIR COSTS
(Thousands of May 1980 Dollars)

Regulatory Alternative[a]	Initial Repair Costs For Model Units[b]			Initial Annualized Repair Costs For Model Units[c]		
	A	B	C	A	B	C
II	4.4	6.7	21	1.00	1.53	4.79
III	3.7	6.0	19	0.84	1.37	4.34
IV	0.8	1.1	4.9	0.18	0.25	1.12
V	0.8	1.1	4.9	0.18	0.25	1.12

[a] Regulatory Alternatives I and VI have zero costs.

[b] From Table 8-5, Labor-Hour Requirements for Initial Leak Repair. Cost = hours x $18.00 per hour.

[c] Initial annualized repair costs for model units = Initial repair cost x capital recovery factor x 1.4. The capital recovery factor (CRF) for model units is determined through the equation:

$$CRF = \frac{i\,(1+i)^n}{(1+i)^n - 1}$$, where n = 10 years and i = 10 percent.

Therefore, the CRF = 0.163.

8.1.2.4 Recovery Credits. VOC emission reductions achieved under each regulatory alternative are expected to be realized as additional marketable product or as additional refinery process heat. The additional product or process heat is referred to as recovery credits. Regulatory Alternative I represents uncontrolled emissions and therefore has no recovery credits. The dollar value of recovery credits achieved under the baseline and Regulatory Alternatives II through VI is based on the May 1980 retail price for LPG and regular gasoline.[13,14] Assuming that the recovered VOC comprises a nominal 60:40 LPG-to-gasoline ratio, the dollar value of the recovered VOC is estimated to be $215 per Mg. Annual VOC emissions, total emission reductions achieved, and dollar values for product recovered annually are presented for each model unit and regulatory alternative in Table 8-8.

8.1.2.5 Net Annualized Costs. The net annualized costs for new affected facilities, shown in Tables 8-9 through 8-11, are determined by subtracting the annual recovered product credit from the total cost before credit. For example, Model Unit A under Regulatory Alternative II has a net annualized cost of $100, representing $12,000 in costs and $11,900 in recovery credits.

8.1.2.6 Cost Effectiveness. The cost effectiveness of the regulatory alternatives for each new affected model unit is shown in Table 8-12. Regulatory Alternatives II, III, IV, and V entail relatively low costs per megagram (Mg) of VOC emission reduction. Model Unit B Regulatory Alternative II and Model Unit C Regulatory Alternatives II and III have net annualized credits. Regulatory Alternative VI proves significantly less cost-effective with ratios for all new model units above $3,000/Mg VOC. The high cost effectiveness ratio of Regulatory Alternative VI results from the high cost of installing sealed bellows valves.

8.1.3 Modified/Reconstructed Facilities

8.1.3.1 Capital Costs. The bases for determining the capital costs for modified/reconstructed facilities are presented in Table 8-1. The capital costs for Alternatives I and II are the same as for new model units. The costs for retrofitting monitoring instruments, caps for open-ended lines, barrier fluid systems and fluid degassing reservoir

Table 8-8. RECOVERY CREDITS[a]

Regulatory Alternative	Model Unit A			Model Unit B			Model Unit C		
	VOC Emissions Mg/yr	Emission Reduction from Regulatory Alternative I Mg/yr	Recovered[b] Product Value $/yr	VOC Emissions Mg/yr	Emission Reduction from Regulatory Alternative I Mg/yr	Recovered[b] Product Value $/yr	VOC Emissions Mg/yr	Emission Reduction from Regulatory Alternative I Mg/yr	Recovered[b] Product Value $/yr
I	80	--	--	170	--	--	485	--	--
II	25	55	11,900	51	119	25,600	150	335	72,000
III	18	62	13,400	36	134	28,800	110	375	80,600
IV	17	63	13,600	33	137	29,500	99	386	83,000
V	14	66	14,200	28	142	30,600	91	394	84,700
VI	6	74	15,900	12	158	34,000	33	452	97,200

[a] Values presented in this table are analogous to LDAR model values presented in Table F-21.

[b] This value is obtained by multiplying the emission reduction from Regulatory Alternative I (recovery credit) in Mg per year by $215 per Mg (May 1980 value of 60:40 LPG to Gasoline Price Ratio). References 13, 14.

Table 8-9. ANNUALIZED CONTROL COST ESTIMATES FOR NEW FACILITIES FOR MODEL UNIT A[a]

(Thousands of May 1980 Dollars)

Cost Item	Regulatory Alternatives				
	II	III	IV	V	VI
Annualized Capital Costs[b]					
A. Control Equipment					
1. Monitoring Instrument	2.1	2.1	2.1	2.1	2.1
2. Caps for Open-Ended Lines	0.60	0.60	0.60	0.60	0.60
3. Dual Mechanical Seals					
o Seals			3.9	3.9	3.9
o Installation			0.33	0.33	0.33
4. Barrier Fluid System for Dual Mechanical Seals			2.1	2.1	2.1
5. Pump Seal Barrier Fluid Degassing Reservoir			4.6	4.6	4.6
6. Compressor Degassing Reservoir Vents		1.3	1.3	1.3	1.3
7. Rupture Disk System					
o Disks		0.40	0.40	0.40	0.40
o Assembly and Installation		1.4	1.4	1.4	1.4
8. Closed-Loop Sampling Connections		0.86	0.86	0.86	0.86
9. Sealed Bellows Valves					169
B. Initial Leak Repair	1.0	0.84	0.18	0.18	
Operating Costs					
A. Maintenance Charges					
1. Monitoring Instrument	3.0	3.0	3.0	3.0	3.0
2. Caps for Open-Ended Lines	0.19	0.19	0.19	0.19	0.19
3. Dual Mechanical Seals			0.44	0.44	0.44
4. Barrier Fluid System for Dual Mechanical Seals			0.65	0.65	0.65
5. Pump Seal Barrier Fluid Degassing Reservoir Vents			1.4	1.4	1.4
6. Compressor Degassing Reservoir Vents		0.40	0.40	0.40	0.40
7. Rupture Disk Systems		0.46	0.46	0.46	0.46
8. Closed-Loop Sampling Connections		0.27	0.27	0.27	0.27
9. Sealed Bellows Valves					52
B. Miscellaneous Charges (taxes, insurance, administration)					
1. Monitoring Instrument	0.37	0.37	0.37	0.37	0.37
2. Caps for Open-Ended Lines	0.15	0.15	0.15	0.15	0.15
3. Dual Mechanical Seals			0.35	0.35	0.35
4. Barrier Fluid System for Dual Mechanical Seals			0.52	0.52	0.52
5. Pump Seal Barrier Fluid Degassing Reservoir			1.1	1.1	1.1
6. Compressor Degassing Reservoir Vents		0.32	0.32	0.32	0.32
7. Rupture Disk System		0.37	0.37	0.37	0.37
8. Closed-Loop Sampling Connections		0.21	0.21	0.21	0.21
9. Sealed Bellows Valves					42
C. Labor Charges					
1. Monitoring Labor	0.61	1.2	1.0	2.8	0.0
2. Leak Repair Labor	2.4	1.8	0.34	0.5	0.0
3. Administrative and Support	1.2	1.2	0.54	1.3	0.0
Total Before Credit	12	17	30	33	291
Recovery Credits	(11.9)	(13.4)	(13.6)	(14.2)	(16)
Net Annualized Cost	0.1	3.6	16.4	18.8	275

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[a] Values presented in this table are analogous to LDAR model values presented in Table F-22.

[b] From Tables 6-1 and 8-1.

Table 8-10. ANNUALIZED CONTROL COST ESTIMATES FOR NEW FACILITIES FOR MODEL UNIT B[a]

(Thousands of May 1980 Dollars)

	Regulatory Alternatives				
Cost Item	II	III	IV	V	VI
Annualized Capital Costs[b]					
A. Control Equipment					
1. Monitoring Instrument	2.1	2.1	2.1	2.1	2.1
2. Caps for Open-Ended Lines	1.2	1.2	1.2	1.2	1.2
3. Dual Mechanical Seals					
o Seals			7.9	7.9	7.9
o Installation			0.65	0.65	0.65
4. Barrier Fluid System for Dual Mechanical Seals			4.2	4.2	4.2
5. Pump Seal Barrier Fluid Degassing Reservoir			9.1	9.1	9.1
6. Compressor Degassing Reservoir Vents		3.9	3.9	3.9	3.9
7. Rupture Disk System					
o Disks		0.93	0.93	0.93	0.93
o Assembly and Installation		3.3	3.3	3.3	3.3
8. Closed-Loop Sampling Connections		1.7	1.7	1.7	1.7
9. Sealed Bellows Valves					338
B. Initial Leak Repair	1.5	1.4	.25	.25	
Operating Costs					
A. Maintenance Charges					
1. Monitoring Instrument	3.0	3.0	3.0	3.0	3.0
2. Caps for Open-Ended Lines	0.37	0.37	0.37	0.37	0.37
3. Dual Mechanical Seals			0.88	0.88	0.88
4. Barrier Fluid System for Dual Mechanical Seals			1.3	1.3	1.3
5. Pump Seal Barrier Fluid Degassing Reservoir Vents			2.8	2.8	2.8
6. Compressor Degassing Reservoir Vents		1.2	1.2	1.2	1.2
7. Rupture Disk Systems		1.1	1.1	1.1	1.1
8. Closed-Loop Sampling Connections		0.53	0.53	0.53	0.53
9. Sealed Bellows Valves					100
B. Miscellaneous Charges (taxes, insurance, administration)					
1. Monitoring Instrument	0.37	0.37	0.37	0.37	0.37
2. Caps for Open-Ended Lines	0.30	0.30	0.30	0.30	0.30
3. Dual Mechanical Seals			0.70	0.70	0.70
4. Barrier Fluid System for Dual Mechanical Seals			1.0	1.0	1.0
5. Pump Seal Barrier Fluid Degassing Reservoir Vents			2.2	2.2	2.2
6. Compressor Degassing Reservoir Vents		0.96	0.96	0.96	0.96
7. Rupture Disk System		0.86	0.86	0.86	0.86
8. Closed-Loop Sampling Connections		0.42	0.42	0.42	0.42
9. Sealed Bellows Valves					83
C. Labor Charges					
1. Monitoring Labor	1.3	2.5	1.9	5.6	0.0
2. Leak Repair Labor	2.6	3.5	0.67	0.99	0.0
3. Administrative and Support	1.6	1.8	1.0	2.6	0.0
Total Before Credit	14	30	57	62	570
Recovery Credits	(25.6)	(28.8)	(29.5)	(30.6)	(34)
Net Annualized Cost	(11.6)	1.2	27.5	31.4	536

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[a] Values presented in this table are analogous to LDAR model values presented in Table F-23.

[b] From Tables 6-1 and 8-1.

Table 8-11. ANNUALIZED CONTROL COST ESTIMATES FOR NEW FACILITIES FOR MODEL UNIT C[a]

(Thousands of May 1980 Dollars)

Cost Item	Regulatory Alternatives II	III	IV	V	VI
Annualized Capital Costs[b]					
A. Control Equipment					
1. Monitoring Instrument	2.1	2.1	2.1	2.1	2.1
2. Caps for Open-Ended Lines	3.6	3.6	3.6	3.6	3.6
3. Dual Mechanical Seals					
o Seals			23	23	23
o Installation			1.9	1.9	1.9
4. Barrier Fluid System for Dual Mechanical Seals			12	12	12
5. Pump Seal Barrier Fluid Degassing Reservoir			26	26	26
6. Compressor Degassing Reservoir Vents		10	10	10	10
7. Rupture Disk System					
o Disks		2.7	2.7	2.7	2.7
o Assembly and Installation		9.1	9.1	9.1	9.1
8. Closed-Loop Sampling Connections		5.2	5.2	5.2	5.2
9. Sealed Bellows Valves					1,000
B. Initial Leak Repair	4.8	4.3	1.1	1.1	
Operating Costs					
A. Maintenance Charges					
1. Monitoring Instrument	3.0	3.0	3.0	3.0	3.0
2. Caps for Open-Ended Lines	1.1	1.1	1.1	1.1	1.1
3. Dual Mechanical Seals			2.5	2.5	2.5
4. Barrier Fluid System for Dual Mechanical Seals			3.7	3.7	3.7
5. Pump Seal Barrier Fluid Degassing Reservoir Vents			8.0	8.0	8.0
6. Compressor Degassing Reservoir Vents		3.2	3.2	3.2	3.2
7. Rupture Disk Systems		3.0	3.0	3.0	3.0
8. Closed-Loop Sampling Connections		1.6	1.6	1.6	1.6
9. Sealed Bellows Valves					310
B. Miscellaneous Charges (taxes, insurance, administration)					
1. Monitoring Instrument	0.37	0.37	0.37	0.37	0.37
2. Caps for Open-Ended Lines	0.89	0.89	0.89	0.89	0.89
3. Dual Mechanical Seals			2.0	2.0	2.0
4. Barrier Fluid System for Dual Mechanical Seals			2.9	2.9	2.9
5. Pump Seal Barrier Fluid Degassing Reservoir Vents			6.4	6.4	6.4
6. Compressor Degassing Reservoir Vents		2.6	2.6	2.6	2.6
7. Rupture Disk System		2.4	2.4	2.4	2.4
8. Closed-Loop Sampling Connections		1.3	1.3	1.3	1.3
9. Sealed Bellows Valves					250
C. Labor Charges					
1. Monitoring Labor	4.5	7.2	5.8	17.0	0.0
2. Leak Repair Labor	4.9	11.0	2.0	3.0	0.0
3. Administrative and Support	3.8	4.8	3.1	8.0	0.0
Total Before Credit	29	73	152	170	1,700
Recovery Credits	(72.0)	(80.6)	(83.0)	(84.7)	(97)
Net Annualized Cost	(43)	(7.6)	69	85	1,600

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[a] Values presented in this table are analogous to LDAR model values presented in Table F-24.

[b] From Tables 6-1 and 8-1.

Table 8-12. COST EFFECTIVENESS FOR MODEL UNITS FOR NEW FACILITIES[a]
(May 1980 Dollars)

	Regulatory Alternative				
	II	III	IV	V	VI
Model Unit A					
Total Capital Cost ($1,000)	13	35	85	85	1,100
Total Annualized Cost ($1,000)	12	17	30	33	291
Net Annualized Cost ($1,000)	0.1	3.6	16	19	275
Total VOC Reduction (Mg/yr)	55	62	63	66	74
Cost Effectiveness ($/Mg VOC)	2	58	250	290	3,800
Model Unit B					
Total Capital Cost ($1,000)	17	73	168	168	2,300
Total Annualized Cost ($1,000)	14	30	57	62	570
Net Annualized Cost ($1,000)	(12)[b]	1.2	28	31	540
Total VOC Reduction (Mg/yr)	119	134	137	142	158
Cost Effectiveness ($/Mg VOC)	(100)[b]	9	200	220	3,400
Model Unit C					
Total Capital Cost ($1,000)	31	190	470	470	6,600
Total Annualized Cost ($1,000)	29	73	152	170	1,700
Net Annualized Cost ($1,000)	(43)[b]	(7.6)[b]	69	85	1,600
Total VOC Reduction (Mg/yr)	335	375	386	394	452
Cost Effectiveness ($/Mg VOC)	(130)[b]	(20)[b]	180	210	3,500

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[a] Values presented in this table are analogous to LDAR model values presented in Table F-25.

[b] Parentheses denote a net credit.

for dual mechanical seals, compressor degassing reservoir vents, closed-loop sampling systems, and sealed bellows valves are the same as costs for new model units. The cost of replacing single mechanical seals with dual mechanical seals is estimated at $1,592; this cost includes 19 labor-hours of installation at $18 per labor hour. Rupture disks for relief valves are estimated to cost from $3,636 to $4,800 per retrofitted relief valve, depending on whether a block valve or 3-way valve is used; the additional costs result from the extra labor-hours expected to be needed to replace a derated relief valve. The total capital cost estimates for modified/reconstructed facilities are presented in Table 8-13.

8.1.3.2 Annualized Costs. The annualized control costs for modified/reconstructed units are derived from the same basis as new units (see Table 8-5). Net annualized costs for modified/reconstructed facilities operating under Regulatory Alternatives I and II are the same as net annualized costs for new facilities. The net annualized costs for modified/reconstructed facilities are higher than for new facilities under Regulatory Alternatives III through VI; higher annualized costs are the result of higher capital costs for rupture disks and dual mechanical seals. The recovery credits for modified/reconstructed facilities are the same as for new units. Annualized control cost estimates for modified/reconstructed facilities operating under Regulatory Alternative III through VI are presented in Tables 8-14 through 8-16.

8.1.3.3 Cost-Effectiveness. The cost-effectiveness of modified/reconstructed facilities operating under the regulatory alternatives is similar to that of new facilities. Like new facilities, modified/reconstructed facilities operating under Regulatory Alternative VI have cost-effectiveness values exceeding $3,000 per Mg of VOC removed. The cost-effectiveness values for reconstructed/modified facilities which are operating under Regulatory Alternatives III through VI are shown in Tables 8-14 through 8-16.

8.1.4 Projected Cost Impacts

The projected fifth-year nationwide costs of implementing Regulatory Alternatives II through VI are compared to the fifth-year nationwide costs of Regulatory Alternative I in Table 8-17. The projected fifth-year nationwide costs of implementing Regulatory Alternatives II through VI

Table 8-13. INSTALLED CAPITAL COST ESTIMATES FOR MODIFIED/RECONSTRUCTED FACILITIES (Thousands of May 1980 Dollars)

Capital Cost Item[a] / Regulatory Alternatives[b]	Model Unit A			Model Unit B			Model Unit C		
	III	IV and V	VI	III	IV and V	VI	III	IV and V	VI
1. Monitoring Instrument	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2
2. Caps for Open-Ended Lines	3.7	3.7	3.7	7.4	7.4	7.4	22	22	22
3. Dual Mechanical Seals									
• Seals		8.8	8.8		18	18		50	50
• Installation		2.4	2.4		4.8	4.8		14	14
4. Barrier Fluid System for Dual Mechanical Seals		13	13		26	26		74	74
5. Pump Seal Barrier Fluid Degassing Reservoir		28	28		56	56		160	160
6. Compressor Degassing Reservoir Vents	8	8	8	24	24	24	64	64	64
7. Rupture Disk System									
• Disks	0.7	0.7	0.7	1.6	1.6	1.6	4.6	4.6	4.6
• Assembly and Installation	12	12	12	28	28	28	80	80	80
8. Closed-loop Sampling Connections		5.3	5.3		11	11	32	32	32
9. Sealed Bellows Valves			1000			2100			6200
Total	34	91	1100	70	180	2300	210	510	6700

[a] From Tables 6-1 and 8-1

[b] For Regulatory Alternatives I and II the capital costs for modified/reconstructed facilities are the same as for new units (Table 8-2).

Table 8-14. ANNUALIZED CONTROL COST ESTIMATES FOR MODIFIED/RECONSTRUCTED FACILITIES FOR MODEL UNIT A[a]
(Thousands of May 1980 Dollars)

	Regulatory Alternatives[b]			
Cost Item	III	IV	V	VI
Annualized Capital Costs[c]				
A. Control Equipment				
1. Monitoring Instrument	2.1	2.1	2.1	2.1
2. Caps for Open-Ended Lines	0.60	0.60	0.60	0.60
3. Dual Mechanical Seals				
o Seals		5.1	5.1	5.1
o Installation		0.39	0.39	0.39
4. Barrier Fluid System for Dual Mechanical Seals		2.1	2.1	2.1
5. Pump Seal Barrier Fluid Degassing Reservoir		4.6	4.6	4.6
6. Compressor Degassing Reservoir Vents	1.3	1.3	1.3	1.3
7. Rupture Disk System				
o Disks	0.4	0.4	0.4	0.4
o Assembly and Installation	2.0	2.0	2.0	2.0
8. Closed-Loop Sampling Connections	0.86	0.86	0.86	0.86
9. Sealed Bellows Valves				169
B. Initial Leak Repair	0.84	0.18	0.18	
Operating Costs				
A. Maintenance Charges				
1. Monitoring Instrument	3.0	3.0	3.0	3.0
2. Caps for Open-Ended Lines	0.19	0.19	0.19	0.19
3. Dual Mechanical Seals		0.56	0.56	0.56
4. Barrier Fluid System for Dual Mechanical Seals		0.65	0.65	0.65
5. Pump Seal Barrier Fluid Degassing Reservoir Vents		1.4	1.4	1.4
6. Compressor Degassing Reservoir Vents	0.40	0.40	0.40	0.40
7. Rupture Disk Systems	0.64	0.64	0.64	0.64
8. Closed-Loop Sampling Connections	0.27	0.27	0.27	0.27
9. Sealed Bellows Valves				52
B. Miscellaneous Charges (taxes, insurance, administration)				
1. Monitoring Instrument	0.37	0.37	0.37	0.37
2. Caps for Open-Ended Lines	0.15	0.15	0.15	0.15
3. Dual Mechanical Seals		0.44	0.44	0.44
4. Barrier Fluid System for Dual Mechanical Seals		0.52	0.52	0.52
5. Pump Seal Barrier Fluid Degassing Reservoir		1.1	1.1	1.1
6. Compressor Degassing Reservoir Vents	0.32	0.32	0.32	0.32
7. Rupture Disk System	0.51	0.51	0.51	0.51
8. Closed-Loop Sampling Connections	0.21	0.21	0.21	0.21
9. Sealed Bellows Valves				42
C. Labor Charges				
1. Monitoring Labor	1.2	1.0	2.8	0.0
2. Leak Repair Labor	1.8	0.34	0.5	0.0
3. Administrative and Support	1.2	0.54	1.3	0.0
Total Before Credit	18	32	34	300
Recovery Credits	(13.4)	(13.6)	(14.2)	(16)
Net Annualized Cost	4.6	18.4	19.8	284
Total VOC Reduction (Mg/yr)	62	63	66	74
Cost Effectiveness ($/Mg)	74	290	300	3,800

[a] Values presented in this table are analogous to LDAR model values presented in Table F-26.

[b] For Regulatory Alternatives I and II the annualized costs for modified/reconstructed facilities are the same as for new units (Table 8-9).

[c] From Tables 6-1 and 8-1.

Table 8-15. ANNUALIZED CONTROL COST ESTIMATES FOR MODIFIED/RECONSTRUCTED FACILITIES FOR MODEL UNIT B[a]
(Thousands of May 1980 Dollars)

Cost Item	Regulatory Alternatives[b]			
	III	IV	V	VI
Annualized Capital Costs[c]				
A. Control Equipment				
1. Monitoring Instrument	2.1	2.1	2.1	2.1
2. Caps for Open-Ended Lines	1.2	1.2	1.2	1.2
3. Dual Mechanical Seals				
o Seals		10	10	10
o Installation		0.78	0.78	0.78
4. Barrier Fluid System for Dual Mechanical Seals		4.2	4.2	4.2
5. Pump Seal Barrier Fluid Degassing Reservoir		9.1	9.1	9.1
6. Compressor Degassing Reservoir Vents	3.9	3.9	3.9	3.9
7. Rupture Disk System				
o Disks	0.9	0.9	0.9	0.9
o Assembly and Installation	4.6	4.6	4.6	4.6
8. Closed-Loop Sampling Connections	1.7	1.7	1.7	1.7
9. Sealed Bellows Valves				338
B. Initial Leak Repair	1.4	0.25	0.25	
Operating Costs				
A. Maintenance Charges				
1. Monitoring Instrument	3.0	3.0	3.0	3.0
2. Caps for Open-Ended Lines	0.37	0.37	0.37	0.37
3. Dual Mechanical Seals		1.1	1.1	1.1
4. Barrier Fluid System for Dual Mechanical Seals		1.3	1.3	1.3
5. Pump Seal Barrier Fluid Degassing Reservoir Vents		2.8	2.8	2.8
6. Compressor Degassing Reservoir Vents	1.2	1.2	1.2	1.2
7. Rupture Disk Systems	1.5	1.5	1.5	1.5
8. Closed-Loop Sampling Connections	0.53	0.53	0.53	0.53
9. Sealed Bellows Valves				100
B. Miscellaneous Charges (taxes, insurance, administration)				
1. Monitoring Instrument	0.37	0.37	0.37	0.37
2. Caps for Open-Ended Lines	0.30	0.30	0.30	0.30
3. Dual Mechanical Seals		0.91	0.91	0.91
4. Barrier Fluid System for Dual Mechanical Seals		1.0	1.0	1.0
5. Pump Seal Barrier Fluid Degassing Reservoir Vents		2.2	2.2	2.2
6. Compressor Degassing Reservoir Vents	0.96	0.96	0.96	0.96
7. Rupture Disk System	1.2	1.2	1.2	1.2
8. Closed-Loop Sampling Connections	0.45	0.45	0.45	0.45
9. Sealed Bellows Valves				83
C. Labor Charges				
1. Monitoring Labor	2.5	1.9	5.6	0.0
2. Leak Repair Labor	3.5	0.67	0.99	0.0
3. Administrative and Support	1.8	1.0	2.6	0.0
Total Before Credit	34	61	67	580
Recovery Credits	(28.8)	(29.5)	(30.6)	(34)
Net Annualized Cost	5.2	31.5	36.4	546
Total VOC Reduction (Mg/yr)	134	137	142	158
Cost Effectiveness ($/Mg)	39	230	260	3,400

[a] Values presented in this table are analogous to LDAR model values presented in Table F-27.

[b] For Regulatory Alternatives I and II the annualized costs for modified/reconstructed facilities are the same as for new units (Table 8-10).

[c] From Tables 6-1 and 8-1.

Table 8-16. ANNUALIZED CONTROL COSTS ESTIMATES FOR MODIFIED/RECONSTRUCTED FACILITIES FOR MODEL UNIT C[a]

(Thousands of May 1980 Dollars

Cost Item	Regulatory Alternatives[b]			
	III	IV	V	VI
Annualized Capital Costs[c]				
A. Control Equipment				
1. Monitoring Instrument	2.1	2.1	2.1	2.1
2. Caps for Open-Ended Lines	3.6	3.6	3.6	3.6
3. Dual Mechanical Seals				
o Seals		29	29	29
o Installation		2.3	2.3	2.3
4. Barrier Fluid System for Dual Mechanical Seals		12.0	12.0	12.0
5. Pump Seal Barrier Fluid Degassing Reservoir		26	26	26
6. Compressor Degassing Reservoir Vents	10	10	10	10
7. Rupture Disk System				
o Disks	2.7	2.7	2.7	2.7
o Assembly and Installation	13	13	13	13
8. Closed-Loop Sampling Connections	5.2	5.2	5.2	5.2
9. Sealed Bellows Valves				1,000
B. Initial Leak Repair	4.3	1.1	1.1	
Operating Costs				
A. Maintenance Charges				
1. Monitoring Instrument	3.0	3.0	3.0	3.0
2. Caps for Open-Ended Lines	1.1	1.1	1.1	1.1
3. Dual Mechanical Seals		3.2	3.2	3.2
4. Barrier Fluid System for Dual Mechanical Seals		3.7	3.7	3.7
5. Pump Seal Barrier Fluid Degassing Reservoir Vents		8.0	8.0	8.0
6. Compressor Degassing Reservoir Vents	3.2	3.2	3.2	3.2
7. Rupture Disk Systems	4.2	4.2	4.2	4.2
8. Closed-Loop Sampling Connections	1.6	1.6	1.6	1.6
9. Sealed Bellows Valves				310
B. Miscellaneous Charges (taxes, insurance, administration)				
1. Monitoring Instrument	0.37	0.37	0.37	0.37
2. Caps for Open-Ended Lines	0.89	0.89	0.89	0.89
3. Dual Mechanical Seals		2.6	2.6	2.6
4. Barrier Fluid System for Dual Mechanical Seals		2.9	2.9	2.9
5. Pump Seal Barrier Fluid Degassing Reservoir Vents		6.4	6.4	6.4
6. Compressor Degassing Reservoir Vents	2.6	2.6	2.6	2.6
7. Rupture Disk System	3.4	3.4	3.4	3.4
8. Closed-Loop Sampling Connections	1.3	1.3	1.3	1.3
9. Sealed Bellows Valves				250
C. Labor Charges				
1. Monitoring Labor	7.2	5.8	17.0	0.0
2. Leak Repair Labor	11.0	2.0	3.0	0.0
3. Administrative and Support	4.8	3.1	8.0	0.0
Total Before Credit	86	161	181	1,700
Recovery Credits	(80.6)	(83.0)	(84.7)	(97)
Net Annualized Cost	5.4	78	96.3	1,600
Total VOC Reduction (Mg/yr)	375	386	394	452
Cost Effectiveness ($Mg)	14	200	240	3,500

[a] Values presented in this table are analogous to LDAR model values presented in Table F-28.

[b] For Regulatory Alternatives I and II the annualized costs for modified/reconstructed facilities are the same as for new units (Table 8-11).

[c] From Tables 6-1 and 8-1.

TABLE 8-17. FIFTH-YEAR NATIONWIDE COSTS
OF THE REGULATORY ALTERNATIVES
ABOVE REGULATORY ALTERNATIVE I COSTS[a,b]
(Thousands of May 1980 Dollars)

Cost Item[c]	Regulatory Alternatives II	III	IV	V	VI
New Units					
Total Capital Cost[d]	1,800	8,200	20,000	20,000	274,000
Total Annualized Cost[e]	1,660	3,400	6,660	7,180	70,000
Total Recovery Credit	3,000	3,370	3,450	3,550	4,000
Net Annualized Cost	(1,340)	30	3,210	3,630	66,000
Modified/Reconstructed Units					
Total Capital Cost[d]	3,700	19,000	47,000	47,000	610,000
Total Annualized Cost[e]	3,290	8,350	15,300	17,000	155,000
Total Recovery Credit	6,610	7,420	7,600	7,800	8,900
Net Annualized Cost	(3,320)	930	7,700	9,200	146,100

[a] Values presented in this table are analogous to LDAR model values presented in Table F-29.

[b] Regulatory Alternative I assumes that no control costs are incurred; therefore, costs for Regulatory Alternatives II through VI are compared to zero.

[c] Parentheses denote savings.

[d] Total cumulative capital costs in 1986.

[e] Annualized costs for model units subject to each regulatory alternative in the fifth year are calculated by multiplying cost estimates for each model unit under each regulatory alternative by the number of affected model units (from Table 7-4).

are compared to the fifth-year nationwide baseline costs in Table 8-18. The cost estimates are obtained by multiplying the costs per model unit by the model unit growth estimates for 1981 to 1986, which are given in Table 7-4. The cost impacts for new units and modified/reconstructed units are reported separately in order to differentiate between expected impacts represented by new units, and maximum impacts represented by the combination of new unit and modified/reconstructed unit impacts. Thus, maximum impacts would result if all changes to existing units constitute modification/reconstruction. The total capital costs reflect the accumulative costs of implementing the regulatory alternatives through 1986. All other costs shown are for units subject to the regulatory alternatives in the fifth year.

8.2 OTHER COST CONSIDERATIONS

8.2.1 General Regulatory Considerations

Environmental, safety, and health statutes that may cause an outlay of funds by the petroleum refining inudstry are listed in Table 8-19. Specific costs to the industry to comply with the provisions, requirements, and regulations of the statutes are unavailable.

Few refineries are expected to close solely due to the cost of compliance with the total regulatory burden, although some may accelerate closings prompted by changing crude supplies and product demand.[15] The costs incurred by the petroleum refining industry to comply with all health, safety, and environmental regulations are not expected to prevent compliance with the regulatory alternatives for refinery fugitive emissions.

8.2.2 New Source and Hazardous Pollutant Standards

As noted above, a review of the total cost of all government regulations affecting petroleum refineries is not feasible. One reason is that the necessary data do not exist; it would require a substantial investment of resources to estimate all of the component costs. Another reason is that there is no generally accepted accounting procedure that permits translation of widely diverse cost impacts into dollars and aggregation of those dollars into a meaningful total.

These limitations are less restrictive if the focus is narrowed to encompass only air pollution standards EPA is considering for

TABLE 8-18. FIFTH-YEAR NATIONWIDE COSTS FOR THE PETROLEUM REFINING INDUSTRY ABOVE BASELINE COSTS[a,b]
(Thousands of May 1980 Dollars)

Cost Item[c]	Regulatory Alternative II	III	IV	V	VI
New Units					
Total Capital Cost[d]	790	7,190	19,000	19,000	273,000
Total Annualized Cost[e]	730	2,470	5,730	6,250	67,200
Total Recovery Credit[f]	1,320	1,690	1,770	1,870	2,320
Net Annualized Cost	(590)	780	3,960	4,380	64,900
Modified/Reconstructed Units					
Total Capital Cost	1,630	16,900	44,900	44,900	607,000
Total Annualized Cost	1,450	6,510	13,500	15,200	153,000
Total Recovery Credit	2,910	3,710	3,900	4,100	5,200
Net Annualized Cost	(1,460)	2,800	9,600	11,100	148,000

[a] Values presented in this table are analogous to LDAR model values presented in Table F-30.

[b] Baseline costs are calculated from baseline emission levels. As discussed in Chapter 7, the baseline VOC emission level represents a weighted average of emissions from refineries operating in National Ambient Air Quality Standard (NAAQS) for ozone attainment areas (no control) and refineries operating in NAAQS for ozone non-attainment areas (CTG controls). Approximately 44 percent of existing refineries are expected to be operating in ozone attainment areas, and 56 percent are expected to be operating in ozone non-attainment areas.

[c] Parentheses denote savings.

[d] Total cumulative capital cost above baseline cost in 1986 = total cumulative capital cost in 1986 for each regulatory alternative - total cumulative capital cost in 1986 for baseline (for example, at new units: 0.56 x $1,800 = $1,008).

[e] Total annualized cost above baseline cost = total annualized cost for each regulatory alternative - annualized cost for baseline (for example, at new units: 0.56 x $1,660= $930).

[f] Total recovery credit above baseline credit = total recovery credit for each regulatory alternative - total baseline recovery credit (for example, at new units: 0.56 x $3,000 = $1,680).

TABLE 8-19. STATUTES THAT MAY BE APPLICABLE TO THE PETROLEUM REFINING INDUSTRY

Statute	Applicable provision, regulation or requirement of statute
Clean Air Act and Amendments	● State implementation plans ● National emission standards for hazardous air pollutant Benzene fugitive emissions ● New source performance standards FCCU unit particulate matter FCC unit carbon monoxide Petroleum storage vessels VOC Claus sulfur recovery plants ● PSD construction permits ● Non-attainment construction permits
Clean Water Act (Federal Water Pollution Control Act)	● Discharge permits ● Effluent limitations guidelines ● New source performance standards ● Control of oil spills and discharges ● Pretreatment requirements ● Monitoring and reporting ● Permitting of industrial projects that impinge on wetlands or public waters ● Environmental impact statements
Resource Conservation and Recovery Act	● Permits for treatment, storage, and disposal of hazardous wastes ● Manifest System to track hazardous wastes ● Recordkeeping, reporting, labeling, and monitoring system for hazardous wastes
Comprehensive Environmental Response, Compensation, and Liability Act	● Superfund
Toxic Substances Control Act	● Premanufacture notification ● Labeling, recordkeeping ● Reporting requirements ● Toxicity testing
Occupational Safety & Health Act	● Walking-working surface standards ● Means of egress standards ● Occupational health and environmental control standards ● Hazardous material standards ● Personal protective equipment standards ● General environmental control standards ● Medical and fist aid standards ● Fire protection standards ● Compressed gas and compressed air equipment standards ● Welding, brazing, and cutting standards
Coastal Zone Management Act	● States may veto federal permits for plants to be sited in coastal zone
State Environmental Policy Acts	● Require environmental impact statements
Safe Drinking Water Act	● Requires underground injection control permits
Marine Sanctuary Act	● Ocean dumping permits ● Recordkeeping and reporting

refineries. Since the Clean Air Amendments of August 1977, EPA has initiated development or revision of numerous new source and hazardous pollutant standards under Sections 111 and 112 of the Clean Air Act. Ten of these actions may result in the imposition of costs on newly constructed, modified, and reconstructed refinery units. These costs are reviewed and cumulated below. The total is conservative because worst case assumptions are used and, except for some product recovery credits, no regulatory benefits are used to offset any of the costs. The results are summarized in Table 8-20, and indicate that the total regulatory cost burden of new source and hazardous pollutant standards does not exceed reasonable bounds. The 10 actions are:

- VOC Fugitive Emissions in the Petroleum Refining Industry - NSPS
- SO_x Emissions from Fluid Catalyst Cracking Unit Regenerators - NSPS
- Benzene Fugitive Emissions - NESHAP
- Benzene Emissions from Benzene Storage Tanks - NESHAP
- Bulk Gasoline Terminals - NSPS
- Asphalt Roofing Industry - NSPS
- Petroleum Liquid Storage Vessels - NSPS
- Volatile Organic Liquid Storage Tanks - NSPS
- VOC Fugitive Emissions - NSPS
- VOC Emissions from Distillation Process Vents in the SOCMI - NSPS.

The costs of the first nine of these potential standards have been considered in this analysis. The last standard listed above has not been included in this analysis because detailed cost estimates are not yet available.

The method used to estimate the effect that each standard will have upon refining costs has three basic steps:

- The collection of fifth-year annualized cost estimates for each standard,
- The adjustment of such costs to a common year's dollars, and
- The determination of the portion of each standard's costs that can be expected to affect petroleum refineries.

Table 8-20. SUMMARY OF FIFTH-YEAR ANNUALIZED COSTS BY STANDARD

Standard	Fifth-Year Annualized Costs (Current $)	Fifth-Year Annualized Costs (May 1980 $)	Refinery Factor	Cost Contribution
VOC Fugitive Emissions in the Petroleum Refining Industry NSPS	$15,300,000 May 1980	$15,300,000	1.000	$15,300,000
SO_x Emissions from Fluid Catalytic Cracking Unit Regenerators NSPS	$73,700,000 November 1980	$70,604,600	1.000	$70,604,600
Benzene Fugitive Emissions NESHAP	$ 2,700,000 May 1979	$ 2,949,915	0.239	$ 705,030
Benzene Emissions from Benzene Storage Tanks NESHAP	$ 1,844,521 February 1979	$ 2,237,488	0.344	$ 769,696
Bulk Gasoline Terminals NSPS	$ 4,300,000 July 1979	$ 4,644,000	0.206	$ 956,664
Asphalt Roofing Industry NSPS	$ 90,000 November 1978	$ 103,538	0.200	$ 20,708
Petroleum Liquid Storage Vessels NSPS	-------	$ 369,600	1.000	$ 369,600
Volatile Organic Liquid Storage Tanks NSPS	($ 5,790,000)[a] February 1980	($ 5,967,763)[a]	0.200	($ 1,192,553)[a]
VOC Fugitive Emissions NSPS	$11,000,000 May 1980	$12,654,651	0.297	$ 3,758,431
	TOTAL			$91,291,176

[a] Parentheses denote savings.

NOTE: These costs have been carried out to the last dollar so that their derivation will be clear; however, the numbers are only, at best, very rough estimates. The fifth-year refers to the fifth-year after implementation of each standard, and does not refer to any one calendar year. Costs are costs to society, less than half of which will be borne by refineries, their owners, customers, and suppliers. See page 8-30.

The method used to estimate the total cost of NSPS and NESHAP standards to the petroleum refining industry relies heavily upon the estimated "fifth-year costs" of each standard. Fifth-year or "nationwide" costs are estimated for all NSPS and NESHAP standards for two reasons. First, because more sources will become subject to a standard as time passes, due to the construction of new and modification/reconstruction of existing sources, annualized costs to the industry will increase as the focus shifts further into the future. Second, because all NSPS and NESHAP standards are reviewed on a five-year basis, to reexamine the need for the effects of regulation, it is not certain that any standard will remain unchanged after 5 years. It should be noted that because fifth-year annualized costs are determined before taxes, they represent total costs to society.

In the adjustment of costs to May 1980 dollars, the Chemical Engineering Plant Cost Index is used.

Several of the standards listed above affect other industries in addition to petroleum refining, such as the Synthetic Organic Chemicals Manufacturing Industry (SOCMI). Thus, an attempt has been made to identify, for each standard, the portion of the annualized costs that can be reasonably attributed to the refining industry. This has been accomplished through the definition of "refinery factors" for each standard.

The determination of estimated cumulative annualized costs for the petroleum refining industry is described below and summarized in Table 8-20.

8.2.2.1 VOC Fugitive Emissions in the Petroleum Refining Industry NSPS. The estimated environmental and economic impacts of this standard are summarized in this document, and the estimated costs of this standard are presented in the various tables of this section. If Regulatory Alternative IV is proposed, the fifth-year annualized costs of this alternative are estimated to be $15,300,000 (May 1980).

Because of costs summarized in this report are expressed in terms of May 1980 dollars, no cost adjustment is required.

Because all of the costs noted above will be incurred by petroleum refineries, the refinery factor is 1.000 and the cost contribution of this standard is $15,300,000.

8.2.2.2 SO$_x$ Emissions from Fluid Catalytic Cracking (FCC) Unit Regenerators NSPS. This NSPS would limit SO$_x$ emissions from FCC unit regenerators and has not yet been proposed. Data pertaining to the costs of this standard have been obtained from Section 9.3 of a draft background information document (BID) prepared for this potential standard.

The project team has noted the probable recommendation of Regulatory Alternative III, which would entail fifth-year annualized costs of $73,700,000 (November 1980).

Costs of this standard have been adjusted by the CE Plant Cost Index where May 1980 = 258.5 and November 1980 = 269.7. Fifth-year annualized costs in May 1980 dollars are therefore $70,604,600.

Finally, because all costs related to this standard will affect petroleum refineries, the refinery factor is 1.000 and thus the cost contribution of this standard is $70,604,600.

8.2.2.3 Benzene Fugitive Emissions NESHAP. This NESHAP, which addresses fugitive benzene emissions from petroleum refinery and SOCMI sources, was proposed on 1/5/81 in Federal Register 46, page 1165. Cost data related to this standard are contained in Benzene Fugitive Emissions - Background Information for Proposed Standards, Draft EIS, EPA-430/3-80-032a, November 1980.

Regulatory Alternative III for both new and existing sources has been proposed and fifth-year costs of $2,700,000 (May 1979) have been estimated.[16]

The costs of this standard have been expressed in terms of May 1980 dollars through the CE Plant Cost Index, which notes that May 1980 = 258.5 and May 1979 = 236.6. Fifth-year annualized costs in May 1980 dollars are therefore estimated to be $2,949,915.

Because this standard affects SOCMI as well as petroleum refinery sources, an attempt has been made to "distribute" total costs among both general types of sources, so that only those costs expected to affect petroleum refineries are considered. This distribution has been accomplished by determining the refinery factor as described below. First, there are 241 units affected by the standard and these units are represented by three model units: A (145 units); B (72 units);

and C (24 units). Furthermore, only 20 of the model A units and 49 of the model B units are found at refineries, while no model C units are located at refineries. Thus, 13.8 percent of model A units and 68 percent of model B units are refinery units. Second, the control costs for each model unit vary with model unit type. Using the sum of costs to control one each of model units A, B, and C as a base, unit A represents 26.0 percent, unit B accounts for 29.8 percent, and unit C represents 44.2 percent of that base. Therefore, because:

$$(.138 \times .260) = (.680 \times .298) = .239,$$

23.9 percent of the fifth-year annualized costs have been assumed to affect petroleum refineries.

Because the fifth-year annualized costs of this standard are $2,949,915 and the refinery factor is .239, $705,030 of the costs have been assigned to refineries.

8.2.2.4 Benzene Emissions from Benzene Storage Tanks NESHAP. This NESHAP would limit benzene emissions from benzene storage facilities, regardless of their location. The standard was proposed on 12/19/80 in Federal Register 45, page 83952, and cost information pertinent to the proposed standard is summarized in Benzene Emissions from Benzene Storage Tanks - Background Information for Proposed Standards, Draft EIS, EPA-450/3-80-034a, December 1980.

As noted in the Federal Register, Regulatory Alternative III is proposed for new sources while Regulatory Alternative IV is proposed for existing sources. The fifth-year annualized costs of these alternatives are estimated to be $1,844,521 (February 1979).[17]

The costs of this standard have been adjusted to May 1980 through the CE Plant Cost Index, which notes that May 1980 = 258.5 and February 1979 = 213.1. Fifth-year annualized costs in May 1980 dollars therefore estimated to be $2,237,488.

Only a portion of these costs will affect petroleum refineries because benzene can be stored at either the production sites, the consumption site, or at bulk terminals. Also, benzene is produced by chemical companies as well as petroleum refineries. With regard to storage sites, it is estimated[18] that of all facilities that store benzene, 43 percent are benzene producers, 54 percent are benzene consumers, and 3 percent are bulk storage terminals. Concerning type of producer, about 80 percent of all benzene produced is done so by petroleum refineries.[19] For these reasons, 34.4 percent (i.e., .43 x .80) of the costs have been assigned to petroleum refineries.

Because the fifth-year annualized costs of this standard are $2,237,488 and the refinery factor is .344, $769,696 of the costs have been assigned to petroleum refineries.

8.2.2.5 Bulk Gasoline Terminals NSPS. This NSPS affects VOC emissions from bulk gasoline truck loading terminals, and was proposed on 12/17/80 by Federal Register 45, page 83126. Cost data related to this standard have been obtained from the Federal Register noted above and Bulk Gasoline Terminals - Background Information for Proposed Standards, Draft EIS, EPA-450/3-80-038a, December 1980.

The proposed standard is in the form of Regulatory Alternative IV and would limit VOC emissions to 35 mg of VOC per liter of gasoline loaded. The fifth-year annualized costs of this standard are estimated to be $4,300,000 (July 1979).[20]

Adjusting costs to May 1980 dollars, where the CE Plant Cost Index notes May 1980 = 258.5 and July 1979 = 239.3, gives fifth-year annualized costs of $4,644,000.

While the BID referenced above does not specify the number of bulk gasoline terminals located at refineries, it does indicate that a total of 1,511 bulk terminals exist.[21] Making the assumption that each of the 311 refineries operating in the United States has one bulk terminal gives an estimate of 20.6 percent of all terminals are located at refineries.

Because the fifth-year annualized costs of this standard are $4,644,000, and the refinery factor is .206, $956,644 of those costs have been assigned to petroleum refineries.

8.2.2.6 Asphalt Roofing Manufacturing Industry NSPS. This NSPS addresses emissions of particulates from asphalt roofing manufacturing activities. One of these activities, specifically the asphalt blowing still, is in some cases found at petroleum refineries. This NSPS was proposed on 11/18/80 by Federal Register 45, page 76404. Cost data pertaining to this standard have been obtained from the Federal Register noted above as well as from Asphalt Roofing Manufacturing Industry - Background Information for Proposed Standards, Draft EIS, EPA-450/3-80-021a, June 1980.

The proposed standard, in the form of Regulatory Alternative V, entails fifth-year annualized costs of $90,000 (November 1978).[22]

The CE Plant Cost Index notes that May 1980 = 258.5 while November 1978 = 224.7. Fifth-year annualized costs in May 1980 dollars are therefore estimated at $103,538.

Because most asphalt blowing stills are located at asphalt roofing plants, rather than petroleum refineries, only a fraction of the costs of this NSPS can be assigned to refineries. It has been observed that while 17 petroleum refineries have blowing stills, 2 asphalt plants and 70 percent of all (118) asphalt roofing plants operate such facilities.[23] For this reason, a refinery factor of .200 or 17/(2 = .7 x 118), has been defined.

Because the fifth-year annualized costs of this standard are $103,538, and the refinery factor is .200, $20,708 are estimated to affect refineries.

8.2.2.7 Petroleum Liquid Storage Vessels NSPS. This NSPS was originally promulgated in 1974 and was revised 4/4/80 by Federal Register 45, page 23373 and all cost data have been obtained from this Federal Register notice.

The annualized costs to control one storage tank with a diameter of 61 meters, has been estimated to range from $1,100 to $3,300, in 1980 dollars.[24]

Fifth-year annualized costs have been estimated through the following method. Because the United States has 18 million barrels per calendar day refining capacity, annual output of petroleum products is estimated at 678,934,817 m^3/year (based upon 65 percent capacity utilization, a conversion factor of 6.29 barrels per cubic meter, and 365 days per year). Also, because each model storage tank has a diameter of 61 meters, the capacity of such a tank is 29,225 m^3 (based upon an assumed tank height of 10 meters). If the average throughput of each tank is 13 times the tank's capacity,[25] each tank has an annual throughput of 379,925 m^3 of petroleum products. This throughput level, along with the annual output estimated above, would indicate the existence of 1,787 tanks (if all tanks had a diameter of 61 meters). Because the IRS allows petroleum refining equipment to be depreciated over a period of 13 to 19 years,[26] the average life of storage tanks is assumed to be 16 years, indicating that about 112 tanks would require replacement each year.

Fifth-year annualized costs are estimated to be $369,600, given $3,300 per tank annualized costs and 112 tanks replaced each year. All costs are assigned to refineries, because the method used to estimate tank population considers storage at refineries alone.

8.2.2.8 Volatile Organic Liquid Storage Tanks NSPS. This NSPS is aimed toward the control of VOC emissions from storage tanks. Information pertaining to the costs of this standard have been obtained from VOC Emissions from Volatile Organic Liquid Storage Tanks - Background Information for Proposed Standards, Draft EIS, EPA-450/3-81-003a, April 1981.

According to the draft EIS, Regulatory Alternative IV is recommended. The fifth-year annualized costs of this alternative are estimated to be a credit of $5,790,000. Such credits are a result of recovered product and are expressed in terms of February 1980 dollars.

The costs of this potential standard have been adjusted to May 1980 dollars through the CE Plant Cost Index, which indicates that May 1980 = 258.5 and February 1980 = 250.8. Fifth-year annualized costs in May 1980 dollars are therefore estimated to be a credit of $5,967,763.

Volatile organic liquids are manufactured by many industries other than petroleum refining, and such liquids are stored at the site of consumption as well as production. For this reason, an attempt has been made to approximate the portion of the costs that can be expected to affect the petroleum refining industry. This portion is estimated to be 20 percent of all industrial organic chemical shipments originate from facilities other than those classified as industrial organic chemical producers by the Department of Commerce.[27]

Because the fifth-year annualized costs of this standard are estimated to be a credit of $5,967,763, and the refinery factor is .200, a credit of $1,193,553 has been assigned to petroleum refineries.

8.2.2.9 VOC Fugitive Emissions - NSPS. This potential NSPS is aimed toward the control of fugitive VOC emissions from the SOCMI, and was proposed on 1/5/81 in Federal Register 46, Number 2, page 1136. Cost information related to this potential standard are presented in VOC Fugitive Emissions in the Synthetic Organic Chemicals Manufacturing Industry - Background Information for Proposed Standards, Draft EIS, EPA-450/3-80-033a, November 1980.

As noted in the Federal Register, Regulatory Alternative IV is recommended and the fifth-year annualized costs of this alternative are $11,000,000 (November 1978).

Costs have been expressed in terms of May 1980 dollars through the CE Plant Cost Index, which indicates that May 1980 = 258.5 and November 1978 = 224.7. Fifth-year annualized costs in May 1980 dollars are estimated to be $12,654,651.

Because this standard affects some SOCMI chemicals that are manufactured at petroleum refineries, an attempt has been made to distribute costs among refineries and other SOCMI sources. According to production data presented by the International Trade Commission[28] SOCMI chemical production is defined according to four groups, with the following levels of 1977 production; Tar and Crudes - 1.48 Gg; Primary Products from Petroleum and Natural Gas - 42.42 Gg; Cyclic Intermediates - 7.12 Gg; and Miscellaneous Cyclic and Acyclic Chemicals - 29.88 Gg. However, within the group called Primary Products from Petroleum and Natural Gas, are included five products are Cumene, Cyclohexane, Styrene, Ethylbenzene, and Ethylene and the total 1977 production of these chemicals was 18.39 Gg. Costs attributable to refineries have been estimated by subtracting this amount from the total produced from petroleum and natural gas and expressing the result as a fraction of total SOCMI production (i.e., 80.9 Gg). This method gives a refinery factor of .297.

Because the fifth-year annualized costs of this proposed standard are estimated to be $12,654,651 and the refinery factor is .297, the cost expected to affect the petroleum refining industry is $3,758,431.

8.3 REFERENCES

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9.0 ECONOMIC IMPACT

9.1 INDUSTRY CHARACTERIZATION

9.1.1 General Profile

9.1.1.1 Refinery Capacity. On January 1, 1980, there were 311 petroleum refineries operating in the United States (excluding Puerto Rico, Virgin Islands, Guam, and the Hawaiian Foreign Trade Zone) with a total crude capacity of 3,005,000 m^3 per stream day.[1] With respect to location, refining capacity is fairly well-concentrated, with 54 percent of domestic crude throughput capacity located in three states: Texas (27%), California (14%), and Louisiana (13%). Table E-1 (Appendix E) summarizes U.S. refining capacity as of January 1, 1980.

Although refining capacity has grown steadily through the 1970s (see Table 9-1), a similar trend in capacity growth is not anticipated during the 1980s. The decrease in the rate of capacity expansion can be traced to demand reductions resulting from rising gasoline prices, the slowdown of economic growth, the availability of substitutes (e.g., coal) in some applications, environmental opposition to new refineries, and the increasing fuel efficiency of newer automobiles. Those additions to capacity that will be made will most likely occur at existing refineries to allow the processing of lower-quality high-sulfur crudes, and increase the output of unleaded gasoline.[12]

It should be noted that in the production and capacity tables that follow, a distinction is often made between stream days (i.e., sd) and calendar days (i.e., cd). The basic difference between the two terms is that "stream day" refers to the maximum capacity of a refinery or unit on a given operating day, while "calendar day" production represents the average daily production over a one-year period. Since most refineries do not operate 365 days each year, stream day numbers are always slightly larger than those for calendar days.

Table 9-1. TOTAL AND AVERAGE CRUDE DISTILLATION CAPACITY BY YEAR[a]
UNITED STATES REFINERIES, 1970-1980

Year (January 1)	Number of Refineries	Total Capacity (m^3/sd)[c]	Average Refinery Capacity (m^3/sd)[c]
1970	253	2,112,000	8,300
1971	247	2,180,000	8,800
1972	247	2,225,000	9,000
1973	247	2,365,000	9,600
1974	259	2,459,000	9,500
1975	256	2,494,000	9,700
1976	266	2,689,000	10,100
1977	285	2,801,000	9,800
1978	289	2,870,000	9,900
1979	297	2,975,000	10,000
1980[b]	311	3,005,000	9,700

[a] References 1 through 11.

[b] Reference 1.

[c] Note: Capacity in stream days.

9.1.1.2 Refinery Production. In terms of total national output, the percentage yields of most refined petroleum products have remained constant over recent years although several exceptions are noted below. The percentage yields of refined petroleum products from crude oil for the years 1969 through 1978 are summarized in Table 9-2, while Table 9-3 notes the average daily output of the major products.

The diversity of refinery product output varies with refinery capacity. Large integrated refineries operate a wide variety of processing units, thus enabling the production of many or all of the products noted in Table 9-2. On the other hand, many refineries are relatively small operations, have only a few processing units, and produce selected products such as distillate oil and asphalt.

Through the 1970's residual fuel oil and petrochemical feedstocks have accounted for increasing shares of total refinery output. These increases can be traced to the use of residual fuel oil in industrial applications and the growth in petrochemical markets due to the increased production of synthetic rubber, fibers, plastics, and other materials manufactured from petrochemicals. The increased output of residual fuel oil and petrochemicals have been balanced by declining output of gasoline and kerosene.

9.1.1.3 Refinery Ownership, Vertical Integration and Diversification. A large portion of domestic refining capacity is owned and operated by large, vertically integrated oil companies, both domestic and international. The remainder is controlled by independent refiners such as Charter, Crown Central Petroleum, Holly, Tosco, and United Refining.

Table 9-4 lists twenty companies with the greatest capacity to process crude oil. Based upon the capacities noted, and a total domestic capacity of 3,005,000 m^3 per stream day,[1] the 4- and 8-firm concentration ratios are 31 and 51 percent, respectively. Since there are currently 158 companies[1] engaged in refining activities, these ratios are indicative of a high degree of ownership concentration of refinery capacity.

Refinery ownership is but one aspect of the vertical integration of the major oil companies. Such companies are integrated "backward" in that they own or lease crude oil production facilities, both domestic and international, as well as the means to transport crude by way of pipeline and tankers. On the international level, access to Saudi Arabian crude is maintained through

Table 9-2. PERCENT VOLUME YIELDS OF PETROLEUM PRODUCTS BY YEAR[a]
UNITED STATES REFINERIES, 1971-1978
(Percent)

Product	1971	1972	1973	1974	1975	1976	1977	1978
Motor Gasoline	46.2	46.2	45.6	45.9	46.5	45.5	43.4	44.1
Jet Fuel	7.4	7.2	6.8	6.8	7.0	6.8	6.6	6.6
Ethane	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Liquefied Gases	2.9	2.8	2.8	2.6	2.4	2.4	2.3	2.3
Kerosene	2.1	1.8	1.7	1.3	1.2	1.1	1.2	1.2
Distillate Fuel Oil	22.0	22.2	22.5	21.8	21.3	21.8	22.4	22.4
Residual Fuel Oil	6.6	6.8	7.7	8.7	9.9	10.3	12.0	12.0
Petrochem. Feedstocks	2.7	2.9	2.9	3.0	2.7	3.3	3.6	3.6
Special Naphthas	0.7	0.7	0.7	0.8	0.6	0.7	0.6	0.6
Lubricants	1.6	1.5	1.5	1.6	1.2	1.3	1.2	1.2
Wax	0.2	0.1	0.2	0.2	0.1	0.1	0.1	0.1
Coke	2.6	2.8	2.9	2.8	2.8	2.6	2.5	2.5
Asphalt	3.8	3.6	3.6	3.7	3.2	2.8	2.9	2.9
Road Oil	0.2	0.2	0.2	0.2	0.1	0.0	0.1	0.1
Still Gas	3.8	3.9	3.9	3.9	3.9	3.7	3.6	3.6
Miscellaneous	0.4	0.4	0.4	0.5	0.7	1.0	1.0	1.0
Processing Gain[b]	- 3.4	- 3.3	- 3.6	- 3.9	- 3.7	- 3.5	- 3.6	- 3.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

[a] Reference 13.

[b] Processing Gain = Product Yield - Process Feed (Input)
Yields are reported as negative because product yields are greater than process feeds. In the catalytic reforming process, for example, straight-chain hydrocarbons are converted to branched configurations with hydrogen as a by-product, resulting in an overall net increase in volume.

Table 9-3. PRODUCTION OF PETROLEUM PRODUCTS BY YEAR[a,b]
UNITED STATES REFINERIES, 1969-1978
(1,000 m^3/cd)

Year	Motor Gasoline	Distillate Fuel Oil	Residual Fuel Oil	Jet Fuel	Kerosene	NGL and LRG[c]
1969	872	370	116	140	45	54
1970	909	391	112	131	42	55
1971	951	397	120	133	38	57
1972	1,000	419	127	135	35	57
1973	1,039	449	154	137	35	60
1974	1,011	424	170	133	25	54
1975	1,037	422	197	138	24	49
1976	1,088	465	219	146	24	54
1977	1,118	521	279	155	27	56
1978	1,140	501	266	155	24	--

[a] Reference 13. Section VII. Tables 5, 6, 6a, 7, 7a, 14, 15, 16, 16a, 17, and 17a.

[b] Total and product output reports may vary slightly by data source.

[c] NGL = Natural Gas Liquids; LRG = Liquefied Refinery Gases.

Table 9-4. NUMBER AND CAPACITY OF REFINERIES OWNED AND OPERATED BY MAJOR COMPANIES[a]
UNITED STATES REFINERIES, 1980

Company	Number of Refineries	Crude Capacity ($1,000\ m^3/cd$)
Exxon	5	251
Chevron	12	233
Amoco	10	197
Shell	8	183
Texaco	12	168
Gulf	7	145
Mobil	7	142
ARCO	4	133
Marathon	4	93
Union Oil	4	78
Sun	5	77
Sohio/BP	3	72
Ashland	7	73
Phillips	5	68
Conoco	7	58
Coastal States	3	47
Cities Service	1	46
Champlin	3	38
Tosco	3	35
Getty	2	35

[a] Reference 12, p. 075.

Aramco which is owned by four international companies: Exxon, Standard Oil of California, Texaco, and Mobil.

With regard to transportation by pipeline, the major oil companies have been the main source of capital for the construction and operation of these facilities, due largely to the huge investments required. On the other hand, tanker ownership is split among the major oil companies and independent operators who charter tankers to oil companies and traders.[14] The presence of independent tanker operators is a result of relatively small financial requirements, compared to pipeline ownership.

While many of the low-volume refinery products are marketed directly by the refiners themselves, the sale of gasoline on the retail level is handled primarily by franchised dealers and independent operators. The major refiners do, however, have a high degree of control over the distribution of their products with regard to market area. This is so since the major refiners select sites for the construction of service stations before the facilities are leased to independent operators under franchise agreements. The major refiners do maintain the direct operation of some service stations for purpose of measuring the strength of the retail market. However, no more than 5 percent of all facilities in operation are managed in this fashion.[15]

Many of the firms that operate refineries, notably the larger oil companies, are diversified as well as vertically integrated. Several refiners are vertically integrated through the manufacture of petrochemicals and resins. Among the firms that have interests in these areas are Clark Oil and Refining, Getty Oil, Occidental Petroleum, and Phillips Petroleum. Ashland Oil's construction division operates the nation's largest highway paving company.

Several instances of diversification can be observed. Exxon Enterprises develops and manufactures various high-technology products. The Kerr-McGee Corporation is the largest supplier of commercial grade uranium for electricity generation and also manufactures agricultural and industrial chemicals. Mobil Oil Corp. is owned by Mobil Corp. which owns both Montgomery Ward and Co. and The Container Corporation of America. The Charter Co., the largest of the independent refiners, is also engaged in broadcasting, insurance, publishing, and commercial printing.

9.1.1.4 Refinery Employment and Wages. Total employment at domestic petroleum refineries has grown steadily since the mid-1960's, with minor disruptions due to the recessions of 1970 and 1974. As Table 9-5 demonstrates,

Table 9-5. EMPLOYMENT IN PETROLEUM AND NATURAL GAS EXTRACTION AND PETROLEUM REFINING BY YEAR[a]

UNITED STATES, 1969-1978

(1,000 Workers)

Year	Petroleum and Natural Gas Extraction	Petroleum Refining
1969	279.9	144.7
1970	270.1	153.7
1971	264.2	152.7
1972	268.2	152.3
1973	277.7	149.9
1974	304.5	155.4
1975	335.7	154.2
1976	360.3	157.1
1977	404.5	160.3
1978	417.1	163.0

[a] Reference 13. Section V. Table 2.

there were 163 thousand workers employed at refineries in 1978.[16] With 289 refineries operating that year,[11] average employment at each refinery is approximately 564 persons.

The average hourly earnings of petroleum refinery workers have consistently exceeded average wage rates for both the mining and manufacturing industries.[17] Petroleum refinery hourly earnings have also exceeded those for other sectors of the oil industry as noted in Table 9-6.

9.1.2 Refining Processes

Refineries process crude oil through a series of physical and chemical processes into myriad products. The four major product areas are as follows:

- Transportation fuels -- motor gasoline, aviation fuel;
- Residential/commercial fuels -- middle distillates;
- Industrial/utility fuels -- residual fuel oils; and
- Other products -- liquified gases and chemical process feeds.

As noted in Table 9-2, motor gasoline is by far the largest volume product of U.S. refineries. Motor gasoline is produced through blending the products of various refinery units such as those described below. Estimated 1981 gasoline pool composition is presented in Table 9-7.

9.1.2.1 Crude Distillation. The initial step in refining crude oil is to physically separate the oil into distinct components or fractions through distillation at atmospheric pressure. There are several possible combinations of fractions and quantities available from crude distillation dependent upon the type of crude being processed and the products desired.[19] High boiling point components are often further separated by vacuum flashing or vacuum distillation. The crude oil still provides feedstock for downstream processing and some final products.[20]

9.1.2.2 Thermal Operations. Thermal cracking operations include regular coking as well as visbreaking. In each of these operations, heavy oil fractions are broken down into lighter fractions by the action of heat and pressure while heavy fuels and coke are produced from the uncracked residue.[21] Visbreaking is a mild form of thermal cracking that causes very little reduction in boiling point but significantly lowers the viscosity of the feed. The furnace effluent is quenched with light gas oil and flashed in the bottom of a fractionator while gas, gasoline, and heavier fractions are recycled.

Coking is a severe form of thermal cracking in which the feed is held at a high cracking temperature long enough for coke to form and settle out.

Table 9-6. AVERAGE HOURLY EARNINGS OF SELECTED INDUSTRIES BY YEAR[a]
UNITED STATES, 1969-1978[a]
($/Hour)[b]

Year	Petroleum Refining	Petroleum and Natural Gas Extraction	Total Manufacturing	Total Mining
1969	4.23	3.43	3.19	3.61
1970	4.49	3.57	3.36	3.85
1971	4.82	3.75	3.57	4.06
1972	5.25	4.00	3.81	4.41
1973	5.54	4.29	4.08	4.73
1974	5.96	4.82	4.41	5.21
1975	6.90	5.34	4.81	5.90
1976	7.75	5.76	5.19	6.42
1977	8.44	6.23	5.63	6.88
1978	9.32	7.01	6.17	7.67

[a] Reference 13. Section V. Table 1.

[b] Current dollars.

Table 9-7. ESTIMATED GASOLINE POOL COMPOSITION BY REFINERY STREAM[a]
UNITED STATES REFINERIES, 1981

Stream	Amount (m^3/cd)	% of Total
Reformate	355,000	29.9
FCC Gasoline	408,000	34.4
Alkylate	162,000	13.7
Raffinate	17,000	1.4
Butanes	75,000	6.3
Coker Gasoline	15,000	1.3
Natural Gasoline	30,000	2.5
Light Hydrocrackate	22,000	1.9
Isomerate	16,000	1.3
Straight Run Naphtha	86,000	7.3
Total	1,186,000	100.0

[a] Reference 18.

The cracked products are separated and drawn off and heavier materials are recycled to the coking operations.[19]

9.1.2.3 Catalytic Cracking. Catalytic cracking is used to increase the yield and quality of gasoline blending stocks and produce furnace oils and other useful middle distillates.[21] By this process the large hydrocarbon molecules of the heavy distillate feedstocks are selectively fractured into smaller olefinic molecules. The use of a catalyst permits operations at lower temperatures and pressures than those required in thermal cracking. In the fluidized catalytic cracking processes, a finely-powdered catalyst is handled as a fluid as opposed to the beaded or pelleted catalysts employed in fixed and moving bed processes.[19]

9.1.2.4 Reforming. Reforming is a molecular rearrangement process to convert low-octane feedstocks to high octane gasoline blending stocks or to produce aromatics for petrochemical uses.[19] Hydrogen is a significant co-product of reforming, and is in turn, the major source of hydrogen for processes such as hydrotreating and isomerization.

9.1.2.5 Isomerizaton. Isomerization, like reforming, is a molecular rearrangement process used to obtain higher octane blending stocks. In this process, light gasoline materials (primarily butane, pentane, and hexane), are converted to their higher octane isomers.

9.1.2.6 Alkylation. Alkylation involves the reaction of an isoparaffin (usually isobutane) and an olefin (propylene or butylenes) in the presence of a catalyst to produce a high octane alkylate, an important gasoline blending stock.[19,21]

9.1.2.7 Hydrotreating. Hydrotreating is used to saturate olefins and improve hydrocarbon streams by removing unwanted materials such as nitrogen, sulfur, and metals. The process uses a selected catalyst in a hydrogen environment.[19] Hydrofining and hydrodesulfurization are two subprocesses used primarily for the removal of sulfur from feedstock and finished products. Sulfur removal is typically referred to as "sweetening".

9.1.2.8 Lubes. In addition to or in place of drying and sweetening of hydrotreating units, petroleum fractions in the lubricating oil range are further processed through solvent, acid, or clay treatment in the production of motor oils and other lubricants. These subprocesses can be used to finish waxes and for other functions.[19]

9.1.2.9 Hydrogen Manufacture. The manufacture of hydrogen has become increasingly necessary to maintain growing hydrotreating operations. Natural gas and by-products from reforming and other processes may serve as charge stocks. The gases are purified of sulfur (a catalyst poison) and processed to yield moderate to high purity hydrogen. A small amount of hydrocarbon impurity is usually not detrimental to processes where hydrogen will be used.[19]

9.1.2.10 Solvent Extraction. Solvent extraction processes separate petroleum fractions or remove impurities through the use of differential solubilities in particular solvents. Desalting is an example whereby water is used to wash water soluble salts from crude.[20] Several complex refining processes employ solvent extraction during the production of benzene-related compounds.

9.1.2.11 Asphalt. Asphalt is a residual product of crude distillation. It is also generated from deasphalting and solvent decarbonizing -- two specialized steps that increase the quantity of cracking feedstock.[20]

9.1.3 Market Factors

9.1.3.1 Demand Determinants. 1980 Department of Energy (DOE) projections conclude that, on the national level, existing refinery capacity is capable of satisfying the future domestic demand for refined petroleum products.[22] Expansions and modifications will, however, be undertaken in order to allow the processing of greater proportions of high-sulfur crudes, and to permit the production of increasing levels of high-octane unleaded gasoline. It is also possible that shifts in demand on the regional level may call for capacity expansions at existing refineries.[22]

Evidence of sufficient refining capacity is provided by Table 9-8. In that table, estimates of percent refinery capacity utilization, along with daily demand levels for the four major refinery products, are presented under several assumptions regarding the world price of oil. In each case the projected utilization rate is well below the 1978 level of 86 percent.

Reduced driving and greater vehicle efficiency have combined to reduce the future demand for motor gasoline. As Table 9-8 indicates, it is unlikely that gasoline demand will, within the forecast period, reach those levels observed during 1978. This conclusion holds true regardless of specific assumptions concerning the future of world oil prices.

Table 9-8. REFINERY CAPACITY, CAPACITY UTILIZATION, AND REFINED PRODUCT DEMAND PROJECTIONS UNDER THREE WORLD OIL PRICE SCENARIOS[a] UNITED STATES REFINERIES, 1978-1985-1990-1995

Year	World Crude Oil Price[b] ($/m^3)	Refinery Capacity (1,000 m^3/cd)	Capacity Utilization (Percent)	Product Demand (1,000 m^3/cd) Motor Gasoline	Distillate Fuel Oil	Residual Fuel Oil	Jet Fuel
1978	97	2,719	86	1,176	572	477	175
1985							
Low	170	3,068	70	1,017	493	223	238
Mid	201	3,068	65	986	461	207	175
High	245	3,068	64	922	445	191	223
1990							
Low	170	3,148	74	1,017	541	238	270
Mid	233	3,148	66	938	493	191	191
High	277	3,148	63	859	461	175	238
1995							
Low	170	3,211	76	1,097	588	207	318
Mid	258	3,211	65	986	493	111	207
High	352	3,211	60	859	429	95	254

[a] Reference 22, p. 115.

[b] Weighted average price including imported, domestic, Alaskan, and stripper oil, etc., in constant (1979) dollars.

Reduced total gasoline demand does not, however, imply that existing gasoline production facilities are currently capable of meeting future gasoline requirements. In particular the continued phase-out of leaded gasoline and demand for higher octane ratings will require some additions to refinery capacity. Consequently, refiners can be expected to increase cracking, catalytic reforming, and alkylation capacities in order to maintain octane requirements.[23]

Distillate fuel oils are used in home heating, utility and industrial boilers, and as diesel fuel. With the exception of diesel fuel, demand in all applications is expected to fall.[22] Declining demand is essentially due to the availability of lower cost substitutes, in particular coal-fired utility boilers, coal-fired industrial boilers and natural gas for home heating purposes. With the exception of low crude oil prices in 1995, Table 9-8 indicates that the demand for distillate fuel oil declines in all cases.

Residual fuel oil is used as a bunker fuel in large ships, large utility and industrial boilers, and in the heating of some buildings. Residual fuel oil competes with coal for use as a fuel in the applications noted above. Table 9-8 shows that the demand for residual fuel oil falls steadily under all price scenarios. This is so because the ability to crack residual fuel into more valuable lighter products ensures that its price will not fall to that point where it can serve as a cost-effective replacement for coal.[24]

The elasticity of demand is a measure of the percent change in demand prompted by a one percent change in price. With regard to the elasticity of demand for various petroleum products, most econometric studies conclude that demand is not sensitive to price changes. Recent estimates made by DOE and summarized in Table 9-9, support this conclusion.[25] Since all values presented in that table are within ± 1, the general conclusion is that demand is not particularly sensitive to price changes.

9.1.3.2 Supply Determinants. As noted in the previous section, it is unlikely that the supply of refined petroleum products will be restricted for reason of inadequate domestic refining capacity. It is, however, quite possible that disruptions in the flow of imported oil could result from international developments, in particular, political instability in the Middle East. The major thrust of national energy policy is therefore the reduction of dependence upon imported oil.

Table 9-9. PRICE ELASTICITY ESTIMATES FOR MAJOR REFINERY PRODUCTS BY DEMAND SECTOR[a]

UNITED STATES, 1985

Demand Sector	Refinery Product	Price Elasticity
Residential	Distillate Oil	-0.4
Commerical	Distillate Oil	-0.4
Industrial	Distillate Oil	-0.5
	Residual Oil	-0.4
	Liquid Gas	-0.4
Transportation	Gasoline	-0.3
	Distillate Oil	-0.7
	Residual Oil	-0.1
	Jet Fuel	-0.4

[a] Reference 22, pp. 332-3.

Attempts to reduce dependence upon imported oil have focused upon three major areas: reduced consumption through conservation, and increased domestic production through both the decontrol of domestic oil prices and the development of a synthetic fuels industry. While price decontrol and synthetic fuels development may have a significant impact in terms of import reductions, these measures are essentially mid- to long-term solutions. Conservation, on the other hand, has offered more immediate results.

The effects of recent conservation efforts, including decreased gasoline consumption, and conversion of facilities to coal and natural gas, can be observed in Table 9-10. In particular, imports of crude oil have leveled-off after reaching a historic high of 384 million m^3 in 1977, while recent reports[26] indicate that the reduction of imports has continued into 1980. The results of conservation efforts can also be observed in the fact that year-end stocks of crude are currently at the highest levels recorded in the recent past.

As part of the Reagan Administration's energy policy, price controls on domestic crude oil and refined petroleum products were revoked by Executive Order 12287 (January 28, 1981). This Order essentially rescinded the price and allocation authority granted to the Department of Energy under the Emergency Petroleum Allocation Act of 1973. The progressive decontrol of domestic crude oil prices has been accompanied by increased exploration, and is expected to increase stocks of already proven reserves. Recent increases in both drilling activities and proven reserves are noted in Table 9-11.

The development of a domestic synthetic fuels industry will have little impact upon energy supplies over the next five years since significant output is not anticipated until the late 1980s.[27]

9.1.3.3 Prices. Table 9-12 indicates recent price levels for gasoline, distillate fuel oil, and residual fuel oil. For each product, a pattern of stable prices, followed by rapid price increases in 1974 and 1979, can be observed. The increases in both years are attributed to the pass-through of increases in the price of crude oil supplied by the OPEC nations.

Future prices of refined products will continue to rise in response to increases in the price of both imported and domestic crude. Table 9-13 presents recent DOE projections of world oil, gasoline, distillate fuel oil, residual fuel oil, and jet fuel prices. With regard to imported oil, it is anticipated that price pressure from the OPEC nations will continue.

Table 9-10. CRUDE OIL PRODUCTION AND CONSUMPTION BY YEAR[a,b]
UNITED STATES, 1970-1979
(1,000,000 m^3/year)

Year	Domestic Production	Imports	Domestic Consumption	Exports	Year-End Stocks	Stocks as Percent of Consumption
1970	559	77	633	0.8	44	6.94
1971	549	98	649	0.1	41	6.36
1972	549	129	680	0.1	39	5.76
1973	534	188	723	0.1	39	5.33
1974	486	202	688	0.2	42	6.13
1975	465	238	703	0.3	43	6.14
1976	452	308	760	0.5	45	5.97
1977	457	384	841	2.9	55	6.57
1978	485	369	854	9.2	60	7.01
1979	474	376	850	13.6	68	8.05

[a] Reference 12, p. 073.

[b] Product volume reports may vary by data source.

Table 9-11. OIL EXPLORATION AND DISCOVERIES BY YEAR[a]
UNITED STATES, 1970-1979

Year	Exploratory Wells Drilled	New Reserves Added (1,000 m^3)
1970	7,693	1,566,000[b]
1971	7,000	15,000
1972	8,357	20,000
1973	7,466	18,000
1974	8,619	36,000
1975	9,163	28,000
1976	9,234	11,000
1977	9,961	25,000
1978	10,667	32,000
1979	10,484	38,000

[a] Reference 12, p. 072.

[b] Includes Prudhoe Bay, Alaska.

Table 9-12. AVERAGE PRICES: GASOLINE, DISTILLATE FUEL OIL, AND RESIDUAL FUEL OIL BY YEAR[d]

UNITED STATES, 1968-1979

Year	Gasoline (¢/liter)		Distillate Fuel Oil (¢/liter)		Residual Fuel Oil (¢/liter)
	Wholesale[a]	Retail[b]	Wholesale[a]	Retail[c]	Wholesale[a]
1968	4.4	8.9	2.7	4.6	1.5
1969	4.5	9.2	2.7	4.7	1.5
1970	4.7	9.4	2.9	4.9	1.9
1971	4.8	9.6	3.1	5.2	2.6
1972	4.7	9.5	3.1	5.2	3.0
1973	5.2	10.3	3.6	6.0	3.4
1974	8.1	13.8	5.6	9.5	6.8
1975	9.5	15.1	8.2	10.3	6.8
1976	10.3	15.7	8.7	11.0	6.6
1977	11.2	16.7	9.8	12.5	7.9
1978	11.8	17.4	9.9	13.4	7.4
1979	16.4	23.2	14.3	19.2	10.2

[a] Excludes tax: Reference 12, p. 079.

[b] Service station price, regular gasoline, includes tax: Reference 13, Section VI, Table 4.

[c] Reference 13, Section VI, Table 5.

[d] Current dollars.

Table 9-13. PRICE PROJECTIONS FOR SELECTED PETROLEUM PRODUCTS BY YEAR[a] UNITED STATES, 1978-1985-1990-1995

($/m^3)[b]

Year	World Crude Oil Price[c]	Motor Gasoline	Distillate Fuel Oil	Residual Fuel Oil	Jet Fuel
1978	97	153	107	80	113
1985					
Low	170	240	185	175	195
Mid	201	277	211	204	221
High	245	320	252	243	263
1990					
Low	170	241	187	176	197
Mid	233	309	242	232	252
High	277	352	295	279	314
1995					
Low	170	240	190	178	199
Mid	258	338	267	255	279
High	352	432	365	352	387

[a] Reference 22, p. 115.

[b] Constant (1979) dollars.

[c] Weighted average price including imported, domestic, Alaskan, and stripper oil, etc.

9.1.3.4 Imports. Imports of both crude oil and refined products are expected to decline through the mid-1980's. In the case of crude oil, the fall in import levels can be attributed to sharp increases in the price of OPEC oil, and the increased production of domestic crude prompted by its price decontrol.

Low sulfur (sweet) crudes are generally more desirable than high sulfur (sour) crudes because the refining of the latter requires a larger investment in desulfurization capacity to meet process as well as environmental needs. While current crude imports are more than half sweet, only 15 percent of OPEC's total oil reserve is sweet crude.[28] Consequently, it is unlikely that the sweet-sour crude import balance will remain constant. The price differential between the two will eventually make sour crude processing a necessary investment.

With regard to refined petroleum products, the importation of most of these products is expected to decline as it has since the mid-1970's. Table 9-14 shows that for the major refined products, imports peaked during 1973-1974. In general, imports of refined products have been relatively small compared with production at domestic refineries. One notable exception is residual fuel oil. The relatively high ratio of imports to domestic production of this product is attributed to the orientation of U.S. refineries toward the production of higher levels of more valuable lighter products, such as motor gasoline, through the "cracking" of residual oil. The importation of greater amounts of residual oil is therefore required to satisfy the requirements of utilities and large industrial boilers in this country.

9.1.3.5 Exports. Exports of crude oil and refined petroleum products are a small portion of total U.S. production, and amount to less than 8 percent of the volume imported.[29] All exports are controlled by a strict licensing policy administered by the U.S. Department of Commerce. Recently, crude oil exports have increased in response to the Canada-United States Crude Oil Exchange Program. The program is mutually beneficial in that acquisition costs are minimized through improved efficiency of transportation.

Table 9-15 summarizes recent trends in major refined product exports. The decline in exports through the 1970s can be attributed to both increased domestic demand and the expansion of foreign refining capacity.

Table 9-14. IMPORTS OF SELECTED PETROLEUM PRODUCTS BY YEAR[a]
UNITED STATES, 1969-1979
(1,000 m^3/cd)

Year	Motor Gasoline	Distillate Fuel Oil	Residual Fuel Oil	Jet Fuel	Kerosene	NGL and LRG
1969	10	22	201	20	0.5	6
1970	11	24	243	23	0.6	8
1971	9	24	252	29	0.2	17
1972	11	29	277	31	0.2	28
1973	21	62	295	34	0.3	38
1974	32	46	252	26	0.8	34
1975	29	25	194	21	0.5	29
1976	21	23	225	12	1.4	31
1977	34	40	216	12	3.0	32
1978	31	27	214	14	1.7	N/A
1979[b]	27	14	178	11	1.4	N/A

[a] Reference 13. Section VII.

[b] Reference 31.

N/A = not available.

Table 9-15. EXPORTS OF SELECTED PETROLEUM PRODUCTS BY YEAR[a] UNITED STATES, 1969-1978 (1,000 m^3/cd)

Year	Motor Gasoline	Distillate Fuel Oil	Residual Fuel Oil	Jet Fuel	Kerosene	NGL and LRG
1969	0.3	0.5	7.3	0.8	0.2	5.6
1970	0.2	0.5	8.6	1.0	-	4.3
1971	0.2	1.3	5.7	0.6	0.2	4.1
1972	0.2	0.5	5.2	0.3	-	4.9
1973	0.6	1.4	3.7	0.8	-	4.3
1974	0.3	0.3	2.2	0.3	-	4.0
1975	0.3	0.2	2.4	0.3	-	4.1
1976	0.5	0.2	1.9	0.3	-	4.0
1977	0.3	0.2	1.0	0.3	-	2.9
1978	0.2	0.5	2.1	0.2	-	N/A

[a] Reference 13. Section VII.

N/A = not available.

9.1.4 Financial Profile

The financial status of the oil industry is generally regarded as strong, a situation that is expected to continue into the 1980s.[30] This optimistic outlook is attributed to: increases in proven domestic reserves and production, decreases in the level of imported oil, and the continuation of the rising price patterns observed in recent years.

Profit margins and returns on investment for both major oil companies and independent refiners are summarized in Tables 9-16 and 9-17. In those tables, profit margin refers to net (after-tax) income as a percentage of sales, while return on investment expresses net (after-tax) income as a percentage of total investment or total assets. The general pattern observed is one of increases in both margins and returns through the five year period noted.

It should be noted that the margins and returns presented in both tables are for companies that refine crude oil but are not necessarily indicative of the profitability of refining activities themselves. An indication of the profitability of refining activities alone is provided by Table 9-18, which summarizes the determination of industry profit margins by quarterly intervals.

9.2 ECONOMIC IMPACT ANALYSIS

9.2.1 Introduction and Summary

In the following section the economic impacts of the regulatory alternatives are discussed. Economic impacts are presented in terms of the potential price and profitability impacts associated with the imposition of each alternative.

As detailed in the following analysis, it is most likely that the cost of regulation will be passed-on to the consumers of refined petroleum products including gasoline, distillate fuel oil, kerosene, and residual fuel oil. For all regulatory alternatives, except Alternative VI, the maximum price increases will not exceed .17 percent at the wholesale level, and will most likely be lower at the retail level. In the event Regulatory Alternative VI is promulgated, price increases as high as 2.88 percent may be possible.

The conclusions noted above are based upon observation of the cost of required controls, the market values of refined petroleum products, and the

Table 9-16. PROFIT MARGINS FOR MAJOR COPORATIONS WITH PETROLEUM REFINERY CAPACITY, BY COMPANY TYPE AND YEAR,[a] 1975-1976
(Percent)

	1975	1976	1977	1978	1979
Integrated-International					
British Petroleum	1.9	1.7	3.0	3.1	8.9
Exxon Corp.	5.6	5.4	4.5	4.6	5.4
Gulf Oil	4.9	5.0	4.2	4.4	5.5
Mobil Corp.	3.9	3.6	3.1	3.2	4.5
Royal Dutch Petroleum	6.7	7.2	6.0	5.0	11.1
Standard Oil (Calif.)	4.6	4.5	4.9	4.8	6.0
Texaco, Inc.	3.4	3.3	3.3	3.0	4.6
Integrated-Domestic					
Amerada Hess	4.0	3.9	3.9	3.0	7.5
Ashland Oil	3.3	3.3	3.4	4.7	8.1
Atlantic Richfield	4.8	6.8	6.4	6.5	7.2
Cities Service	4.3	5.5	4.8	2.5	5.5
Clark Oil and Refining	0.9	1.3	1.6	1.6	3.6
Conoco, Inc.	4.6	5.8	4.4	4.8	6.4
Earth Resources	4.5	4.6	4.5	2.9	4.1
Getty Oil	8.6	8.5	9.9	9.3	12.5
Kerr-McGee	7.3	6.9	5.5	5.7	6.0
Marathon Oil	4.5	5.6	4.6	4.4	4.4
Phillips Petroleum	6.7	7.2	8.2	10.2	9.4
Shell Oil	6.3	7.6	7.3	7.4	7.8
Standard Oil (Indiana)	7.9	7.7	7.6	7.2	8.1
Standard Oil (Ohio)	5.1	4.7	5.2	8.7	15.0
Sun Co.	5.0	6.6	5.6	4.9	6.6
Union Oil of California	4.6	5.0	5.9	6.4	6.6
Refiners					
Charter Co.	1.0	1.5	1.3	1.2	8.7
Crown Central Petroleum	1.2	2.4	2.0	2.8	6.8
Holly Corp.	3.1	4.0	3.8	3.5	2.6
Tosco Corp.	N/A	0.9	1.2	1.6	4.1
United Refining	1.8	0.8	2.1	2.1	3.4

[a]Reference 12, p. 088.

N/A = not available.

Table 9-17. RETURN ON INVESTMENT FOR MAJOR CORPORATIONS WITH PETROLEUM REFINING CAPACITY, BY COMPANY TYPE AND YEAR,[a] 1975-1979

(Percent)

	1975	1976	1977	1978	1979
Integrated-International					
British Petroleum	2.0	2.1	4.3	4.1	11.8
Exxon Corp.	7.8	7.6	6.5	6.9	9.5
Gulf Oil	5.6	6.3	5.4	5.4	8.2
Mobil Corp.	5.6	5.5	5.1	5.2	8.0
Royal Dutch Petroleum	6.8	8.4	8.0	6.0	13.5
Standard Oil (Calif.)	6.3	6.6	7.1	7.0	10.2
Texaco, Inc.	4.8	4.9	5.0	4.4	8.1
Integrated-Domestic					
Amerada Hess	5.5	5.9	6.0	4.2	11.3
Ashland Oil	6.3	6.6	6.7	8.8	20.2
Atlantic Richfield	5.2	7.1	6.8	6.7	8.9
Cities Service	4.5	6.3	5.7	3.0	7.9
Clark Oil and Refining	1.7	3.0	4.5	4.9	10.6
Conoco, Inc.	6.7	8.0	6.0	6.4	9.7
Earth Resources	12.9	12.8	10.9	7.2	8.5
Getty Oil	8.2	7.5	8.0	7.4	11.2
Kerr-McGee	10.1	8.9	6.9	6.1	7.3
Marathon Oil	6.7	7.8	6.1	5.5	7.3
Phillips Petroleum	8.0	8.5	9.5	11.1	11.5
Shell Oil	7.8	9.4	8.7	8.3	8.4
Standard Oil (Indiana)	8.4	8.5	8.4	8.0	9.6
Standard Oil (Ohio)	3.6	2.6	2.3	5.0	13.4
Sun Co.	5.2	7.8	6.6	6.8	10.2
Union Oil of California	6.3	6.3	7.0	7.3	8.7
Refiners					
Charter Co.	2.0	3.2	3.2	3.4	29.1
Crown Central Petroleum	2.9	5.3	5.1	6.4	16.8
Holly Corp.	9.1	11.1	10.6	9.9	8.0
Tosco Corp.	N/A	2.6	2.8	4.2	14.2
United Refining	5.0	2.1	5.6	6.2	11.0

[a] Reference 12, p. 087-088.

N/A = not available.

Table 9-18. PETROLEUM REFINING INCOME DATA BY QUARTER[a]
UNITED STATES REFINERIES, 1978-1980
($1,000,000,000)[c]

	1978				1979				1980
	1	2	3	4	1	2	3	4	1
Sales	41.75	43.88	46.17	48.52	50.72	54.71	63.68	73.58	79.80
Net Income Before Tax	3.05	3.77	4.14	4.23	4.65	6.16	6.62	7.81	8.55
Net Income	2.55	3.15	3.41	3.66	3.95	5.25	5.71	6.84	8.04
% Net Income to Sales[b]	6.11	7.18	7.39	7.54	7.79	9.60	8.97	9.30	10.08

[a] Reference 12, p. 082.

[b] Profit margin.

[c] In current dollars.

strength of market demand for such products. The projections of economic impacts discussed below are based upon the capital and net annualized control costs presented in Chapter 8. Economic impacts have been estimated based upon industry growth and supply and demand balances projected for the five year period including the years 1982 through 1986.

9.2.2 Economic Impact Methodology

9.2.2.1 Estimation of Model Unit Revenues. Each of the model units described in Chapter 6 represents a group of several types of refinery process units, including those that produce directly marketable products (e.g. gasoline and asphalt), as well as those that produce products subject to further refining by downstream units (e.g. reformate and isomerate). However, in order to provide a common basis by which price and profitability impacts may be evaluated at the model unit level, the revenue potential of each model unit has been estimated as the approximate market value of each unit's output, regardless of whether that output is sold or processed further.

The determinations of daily revenues for model units A, B, and C are summarized in Tables 9-19, 9-20, and 9-21 respectively. Each table includes the following information related to each model unit;

- The unit types represented by the model unit,
- The major products of each unit type,
- The average daily capacity of each major product,
- The May 1980 wholesale price of each major product, and
- A weighting factor that represents the projected growth in unit capacity.

Since the model units described in Chapter 6 do not specify capacity/output levels, those output levels noted in Tables 9-19, 9-20, and 9-21, are representative of the daily capacities of the "smaller" units currently in operation. In this way the analysis is representative of the worst case situation, since most units affected by this standard will probably have larger capacity levels, and thus be capable of spreading control costs over a larger volume of output.

In Tables 9-19, 9-20, and 9-21, the daily revenues of each model unit are approximated by way of a two-step process. First, the daily value of the output of each unit type is estimated through observation of the amount and price of each product of each unit type. Then, daily model unit revenues are

Table 9-19. REVENUE ESTIMATION-MODEL UNIT A
(May 1980 Dollars)

Unit Type	Product	Output (m^3/cd)	x	Price ($/$m^3$)	=	Value ($/cd)	x	Weighted Growth	=	Model Unit Revenue ($/cd)
Hydrotreating-	Distillate Fuel	238		205[a]		48,790				
	Residual Fuel	238		100[a]		23,800				
						72,590		.72		52,265
Isomerization-	Isobutane, Isopentane, etc.	477		79[b]		37,683		.03		1,130
Lubes-	Lubricating Oils	477		120[b]		57,240		.06		3,434
Asphalt-	Asphalt	477		120[b]		57,240		.06		3,434
Hydrogen-	Hydrogen	560,000		32.1/ 1,000 m^3[b]		18,000		.13		+2,340
								1.00		62,603

[a] Reference 32.

[b] Reference 33.

Table 9-20. REVENUE ESTIMATION-MODEL UNIT B

(May 1980 Dollars)

Unit Type	Product	Output (m^3/cd)	x	Price ($/$m^3$)	=	Value ($/cd)	x	Weighted Growth	=	Model Unit Revenue ($/cd)
Alkylation-	Alkylates	954		264^a		251,856		.06		15,111
Thermal Cracking-	Coke	397		151^a		59,947				
	Gas & Naphtha	238		79^a		18,802				
	Light & Heavy Gas Oil	477		157^a		74,889				
						153,638		.19		29,191
Reforming-	Gasoline & Aromatics	795		264^a		209,880				
	LPG	159		79^a		12,561				
	Hydrogen	168,000		32.1/ 1,000 m^{3a}		5,400				
						227,841		.48		109,364
Vacuum Distillation-	C_4 & Light Dist.	318		79^a		25,122				
	Kerosine & Mid Distillates	159		211^a		33,549				
	Vacuum Gas Oil & Residuals	795		126^a		100,170				
						158,841		.27		+42,887
								1.00		196,553

[a] Reference 33.

Table 9-21. REVENUE ESTIMATION-MODEL UNIT C

(May 1980 Dollars)

Unit Type	Product	Output (m^3/cd)	x	Price ($/$m^3$)	=	Value ($/cd)	x	Weighted Growth	=	Model Unit Revenue ($/cd)
Crude	C_4 & Light Dist.	397		79[b]		31,363				
Distillation-	Kerosene & Mid Distillates	238		211[b]		50,218				
	Gas Oil & Residuals	954		126[b]		120,204				
						201,785		.68		137,214
Catalytic	LPG	318		79[b]		25,122				
Cracking-	Gasoline	1,033		235[a]		242,755				
	Light & Heavy Gas Oil	238		157[b]		37,366				
						305,243		.32		+97,678
								1.00		234,892

[a] Reference 32

[b] Reference 33.

Table 9-22. ANNUAL REVENUE SUMMARY BY MODEL UNIT (May 1980 Dollars)

Model Unit	Full Capacity Daily Revenue ($/cd)	Full Capacity Annual Revenue ($/year)[d]	Capacity Utilization (percent)	Projected Annual Revenue ($/year)
A	62,603[a]	22,850,095	65[e]	14,852,562
B	196,553[b]	71,741,845	65[e]	46,632,199
C	234,892[c]	85,735,580	65[e]	55,728,127

[a] Table 9-19.

[b] Table 9-20.

[c] Table 9-21.

[d] Calendar year.

[e] Reference 34.

estimated by way of a weighted average, with weights assigned according to future unit growth projections as presented in Appendix E. It should be noted that since the revenue levels presented are based upon unit capacities, an adjustment is required since it is highly unlikely that the affected units will operate at full capacity over the forecast period (i.e., up to and including 1986).

Annual revenues expected to be generated by each model unit are summarized in Table 9-22, which notes the potential revenues of units operating at full capacity, the projected rate of capacity utilization, and the annual revenues associated with operation at less than full capacity. The projected rate of refinery capacity utilization (65%) is that estimated by the U.S. Department of Energy (see Table 9-8) for the year 1985. The projected annual revenues noted in Table 9-22 are those used in the estimation of price and profitability impacts as detailed below.

9.2.2.2 Estimation of Price Increases Under Full Cost Pricing. The method used to estimate the price consequences of the control costs presented in Chapter 8, is based upon the assumption that refiners can and will increase the prices of refined products to a level required to cover the net annualized costs to control fugutive VOC emissions from both new and modified/reconstructed units. Under this assumption all control costs are eventually borne by the consumers of refined petroleum products. Such a full cost pricing assumption is supported by both the low elasticity of demand for refined products (see Section 9.1.3.1), and the relatively small price increases required to cover the estimated control costs.

The specific method used to estimate price increases is the expression of the net annualized control costs, for each model unit and regulatory alternative, as a percentage of what the revenue of the unit would be in the absence of regulation. Such percentages are therefore indicators of the percentage increases in model unit revenues, and thus product prices, needed if profits after the implementation of a regulatory alternative are to remain unaffected. This method assumes that output remains unchanged and that refiners will not seek a return on the required investment in control equipment. If in fact prices are set so that return on investment remains constant, price increases as estimated by the method used in this analysis may be slightly understated, (i.e. by less than .01 percent in the worst case).

Potential price increases, estimated through the method noted above, are summarized in Section 9.2.3.1, while the estimates of net annualized control costs are presented in Tables 8-9, 8-10, and 8-11 for new units, and Tables 8-14, 8-15, and 8-16 for modified/reconstructed units. Estimates of model unit revenues in the absence of an NSPS are described in Section 9.2.2.1.

9.2.2.3 Estimation of Profitability Impacts Under Full Cost Absorption. In the unlikely event that refiners affected by this standard are unable to pass the costs of control on to the consumers of refined petroleum products, the profitability of particular refining activities could be decreased. In an attempt to measure the extent of such profitability impacts, a comparison of profit margins before and after regulation has been made.

There are two commonly used measures of profitability. Profit margin is the ratio of net (after-tax) income to sales, while the return on investment (ROI) is the ratio of net (after-tax) income to total investment or assets. Both measures are directly related by way of the asset turnover ratio, or the ratio of sales to total investment. The relationship can be expressed as follows:

$$\frac{\text{net income}}{\text{sales}} \times \frac{\text{sales}}{\text{investment}} = \text{ROI},$$

and explains why low profit margin, high turnover industries such as retailing, may show the same ROI as a high profit margin, low turnover industries such as heavy manufacturing. Since this analysis has already estimated sales revenues for model units (Section 9.2.2.1), and is not complicated by interindustry comparisons that would introduce wide variations in the asset turnover ratio, the estimation of profitability impacts are discussed in terms of changes in profit margins for the affected refining activities.

In practice, profit margin is expressed as a percentage rather than a ratio as described above. Pre-control profit margins are therefore determined by:

$$\text{Pre-control Profit Margin} = (NI/AR) \times 100$$

where: NI = Net Income (annual), and
AR = Annual Revenue (sales).

Pre-control profit margins and full cost absorption are determined under the assumption that net income will be reduced by an amount equal to the after-tax cost of control. After-tax costs are of concern since increased costs, in the absence of increased revenues, imply both reductions in taxes as well as net income. Post-control profit margins with full cost absorption are therefore determined by:

$$\text{Post-control Profit Margin} = ((NI-(NACC \times (1-t)))/AR) \times 100,$$

where: NI = Net Income (annual),

AR = Annual Revenue (sales),

NACC = Net Annualized Control Costs, and

t = Tax Rate (as a decimal).

Annual revenue estimates for each model unit are detailed in Tables 9-19, 9-20, and 9-21. Net annualized control costs are those presented in Tables 8-9, 8-10, and 8-11 for new units and Tables 8-14, 8-15, and 8-16 for modified/reconstructed units. The tax rate is assumed to be 46 percent since this is the current Federal tax rate for taxable income greater than $100,000. Finally, net income for each model unit is determined based upon a profit margin of 5.12 percent in the absence of control. Net income for each model unit can therefore estimated as follows:

$$NI = AR \times .0512.$$

The baseline profit margin used in this analysis, 5.12 percent, has been selected since it is the average (1979) profit margin reported for Refiners in Table 9-16 and is considered conservative in light of recently increasing margins (see Table 9-18). The estimation of profit margins with the regulatory alternatives and full cost absorption is made in Section 9.2.3.2.

9.2.3 Economic Impacts

9.2.3.1 Price Impacts. As noted in Section 9.2.2.2 potential price increases of refined petroleum products have been estimated through the expression of net annualized control costs as a percentage of individual model unit revenues. The results of that procedure, summarized in Table 9-23 for for both new and modified/reconstructed units, show that for all regulatory alternatives, with the exception of Alternative VI, maximum potential price increases are less than .17 percent. As noted previously, it is most likely that the very small percentage price increases associated with Regulatory Alternatives II through V will not be resisted by consumers in the form of decreased consumption. Consequently, the potential for industry impacts, resulting from control-related demand reductions, is very low.

This conclusion is based upon two major observations. First, the estimated elasticity of demand for refined petroleum products (see Table 9-9) is very low, due largely to the lack of reasonable substitute products. The basic implication of low elasticity is that refiners can pass-on cost increases and not experience significant reductions in demand. Second, the recent history of rapid increases in the costs of imported crude oil along with the price decontrol of domestically produced crude, have caused a well-publicized rapid escalation in refined product prices. For example, for the year November 1979 to November 1980 alone, wholesale prices for motor gasoline, distillate fuel and residual fuel increased 28.7, 20.1, and 32.5 percent respectively.[36] It is therefore unlikely that the worst case price increases noted in Table 9-23 will cause further disruption under the already highly volatile market situation.

It should be noted that the price increases discussed above are those related to a situation where one refinery unit becomes subject to regulation. In the event that a refinery constructs, reconstructs, or modifies more than one unit, potential price increases may be slightly higher, dependent upon the number, type, and size of additional units affected.

9.2.3.2 Profitability Impacts. For reasons noted in the previous section, it is highly unlikely that the profitability of refining activities will be affected by the imposition of control costs related to this standard. However, this analysis has attempted to quantify the profitability reductions associated with the inability of refiners to increase prices to a level sufficient to cover those increased costs.

The method used in the estimation of profitability reduction is detailed in Section 9.2.2.3, while the results of that procedure are summarized in Table 9-24. As in the case of price increases, maximum potential profit margin reductions are very low for Regulatory Alternatives II through V, and if incurred, would most likely not affect decisions related to refinery unit construction or modification. Regulatory Alternative VI however, does entail significant reductions in profitability for all model units.

9.2.3.3 Capital Availability Impacts. Each of the regulatory alternatives requires that capital expenditures be made for the purchase of control equipment. These capital control costs are summarized in Table 8-2 for new units and Table 8-13 for modified/reconstructed units.

Table 9-23. PERCENT INCREASES IN PRICE UNDER FULL COST PRICING BY MODEL UNIT*

Unit Type	Regulatory Alternative				
	II	III	IV	V	VI
New Units					
A	.00	.02	.11	.13	1.85
B	(.02)	.00	.06	.07	1.15
C	(.08)	(.01)	.12	.14	2.70
Modified/Reconstructed					
A	.00	.03	.12	.13	1.91
B	(.02)	.01	.07	.08	1.17
C	(.08)	.01	.14	.17	2.88

*Values presented in this table are based on the ABCD model discussed in Section 4.2.3.4. Analogous LDAR model values are presented in Table F-31.

Table 9-24. PROFIT MARGINS UNDER FULL COST ABSORPTION BY MODEL UNIT*

(Baseline Profit Margin = 5.12 Percent)

Unit Type	Regulatory Alternative				
	II	III	IV	V	VI
New Units					
A	5.12	5.11	5.06	5.05	4.12
B	5.13	5.12	5.09	5.08	4.50
C	5.16	5.13	5.05	5.05	3.66
Modified/Reconstructed					
A	5.12	5.10	5.05	5.05	4.09
B	5.13	5.11	5.08	5.08	4.49
C	5.16	5.11	5.04	5.03	3.57

*Values presented in this table are based on the ABCD model described in Section 4.2.3.4. Analogous LDAR model values are presented in Table F-32.

The need to purchase additional capital equipment requires that investors in new refinery units must obtain capital financing above that which would be required in the absence of regulation. Therefore, in order to project the potential for impacts related to the high cost, or unavailability of debt financing, an estimate of the percent increase in capital requirements has been made by comparing capital control costs to the capital requirements for construction of an uncontrolled refinery.

The U.S. Department of Energy has estimated[37] that new refinery construction in 1979 required an expenditure of \$22,015 per m^3 capacity per stream day. Furthermore, the average size of the 64 small refineries constructed during the period 1974 to 1980 is 2226 m^3 per calendar day[38], or 2,368 m^3 per stream day assuming a calendar to stream day ratio of .94.[1] Therefore the small refinery is estimated to require an investment of \$52.1 million (1979) or \$56.3 million after adjustment to May 1980 dollars.[39]

Inspection of Table 8-2 shows that for Regulatory Alternatives II through V capital control costs for any model unit do not exceed \$.47 million. For these alternatives therefore, the worst case situation, that is the most costly regulatory alternative and smallest refinery, shows an increase in capital investment requirements of less than one percent. This fact together with improved earnings and cash generation should enable refiners to finance capital expenditures without using outside funds,[40] and thus avoid potential problems related to the unavailability or high cost of debt financing.

9.3 SOCIOECONOMIC AND INFLATIONARY IMPACTS

Section 9.2 described potential impacts of the regulatory alternatives largely from the viewpoint of the refining industry. Section 9.3 expands this perspective to encompass the whole economy. In addition, impacts on small businesses and other small-scale concerns are reviewed.

9.3.1 Fifth-Year Annualized Costs

The total dollar cost of an NSPS increases over the first few years as more and more new sources are constructed, and old sources are modified and reconstructed. Then, as control equipment is depreciated and new units are retired, modified, or reconstructed, the cost levels out and may decline. To facilitate the analysis, comprehension, and comparison of many diverse regulations, the Environmental Protection Agency, for each regulatory alternative, calculates one uniform measure of this total cost. This is the fifth-year annualized cost. It is a before-tax figure, about half of which will be deducted from the taxes corporations must pay. Thus, the results are projections of the total dollar costs of control not just to industry, but to society as a whole.

Appendix E describes and summarizes the results of the method used to project the construction of new, and the reconstruction and modification of existing, refinery units that will be subject to this standard up to the year 1986. According to those projections and the net annualized cost estimates presented in Chapter 8, the total net annualized costs in the fifth-year after regulation have been estimated. For all regulatory alternatives with the exception of Alternative VI, such costs are less than $15.44 million. The fifth-year annualized costs above baseline estimates are ($2.05), $3.58, $13.55, $15.44, and $212.99 million, for Regulatory Alternatives II, III, IV, V, and VI respectively. The fifth-year costs are estimated by the multiplication of net annualized control costs by the number of units expected to be affected through 1986. The results of this procedure are summarized in Table 9-25.

9.3.2 Inflationary Impacts

Under Regulatory Alternatives II through V, maximum potential wholesale price increases for refined petroleum products are less than .17 percent. For this reason the imposition of those regulatory alternatives will cause virtually no increase in the rate of inflation as measured by either the Consumer Price Index or Producer Price Index. However promulgation of a standard in the form of Regulatory Alternative VI, with possible price increases of as much as 2.88 percent, could have some impact upon the rate of inflation.

9.3.3 Employment Impacts

With the exception of Regulatory Alternative VI the cost of control should have very little impact upon the demand for the products of, or the profitability of the affected units. For this reason the decision to construct new or modify existing refinery units will be unaffected by such controls. Under such circumstances, the standard will have no negative impact upon employment trends in the petroleum refining industry. On the other hand, since each of the regulatory alternatives entails additional labor support for monitoring and the maintenance of control equipment, slightly positive employment impacts could result.

Table 9-25. SUMMARY OF FIFTH-YEAR NET ANNUALIZED COST[a,b]

(Thousands of May 1980 Dollars)

Unit Type	Regulatory Alternative				
	II	III	IV	V	VI
New Units	(591)[c]	782	3,956	4,376	64,819
Modified/Reconstructed	(1,462)[c]	2,793	9,590	11,064	148,166
TOTAL	(2,053)[c]	3,575	13,546	15,440	212,985

[a] Values presented in this table are based on the ABCD model discussed in Section 4.2.3.4. Analogous LDAR model values are presented in Table F-33.

[b] Costs are "above baseline" costs as explained in Section 3.3.

[c] Parentheses indicate net cost reduction due to product recovery credits.

9.3.4 Balance of Trade Impacts

As noted in Sections 9.1.3.4 and 9.1.3.5 the import and export of refined petroleum products represent very small portions of total domestic production and consumption. This fact together with the small price and profitability impacts previously noted indicate no potential for impact upon the United States balance of trade.

9.3.5 Regulatory Flexibility Act - Small Refinery Impacts

The Regulatory Flexibility Act of 1980 requires the identification of the potentially adverse effects of all Federal regulations upon small businesses, small governmental units, and small non-profit organizations. According to current Small Business Administration guidelines established for the purpose of providing pollution control guarantee assistance under Public Law 94-305, (43 Federal Register 36052, August 15, 1978) a small business in the petroleum refining industry is one that has fewer than 1,500 employees. This total includes the refinery itself along with any affiliated operations.

At the present time there are many small companies that refine petroleum and employ fewer than 1,500 persons. A primary reason for the large population of small refineries is the existence of Federal government subsidy programs that prompted the construction of many small refineries during the 1970's. Specific subsidies such as the "small refiners bias" built into the DOE crude oil entitlements program have had the effect of neutralizing the diseconomies of scale that are inherent in small refinery operations. Such subsidy programs were effective in encouraging the construction of small refineries to the extent that about 64 refineries having average capacity of 2,226 m^3 per calendar day were constructed during the period January 1, 1974 to January 1, 1980.[38]

It is not expected that any totally new "grass roots" refineries will be constructed within the next five years. Furthermore, very few of the small refineries that are currently in operation will become subject to the regulatory alternatives previously described. This is true for two reasons. First, the recent price decontrol of crude oil and refined petroleum products (Executive Order 12287, January 28, 1981) has had the effect of eliminating the subsidies noted above, thus removing the competitive advantage those subsidies provided. Consequently, small refineries, for reasons unrelated to the regulatory alternatives, may lack the ability to attract the capital resources required to finance new unit construction and reconstruction or modification. Second, the fact that many of the small refineries currently in operation were constructed during the 1970's suggests that they have not depreciated to the point where reconstruction or modification is necessary. Therefore, because Section 111 standards apply only to newly constructed, modified or reconstructed units, few of the small refineries are expected to be subject to the regulatory alternatives.

If any small refineries should become subject to the regulatory alternatives they will not be adversely affected. This can be said because the price and profitability impacts previously described have been estimated from the perspective of the "smaller" refinery units currently in operation. Thus the results presented can be accurately interpreted as those that may affect small refineries that become subject to this regulation. It can be concluded, therefore, that the regulatory alternatives in the form described in the previous sections, will have no significant economic impact upon small refineries.

9.3.6 Executive Order 12291

According to the directives of Executive Order 12291 "major rules" are those that are projected to have any of the following impacts:

- an annual effect on the economy of $100 million or more,
- a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions, or
- significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of United States - based enterprises to compete with foreign-based enterprises in domestic or export markets.

If a regulation is determined to be a major rule as defined above, the regulatory agency is required to undertake a Regulatory Impact Analysis, the form and content of which is described in Section 3 of the Executive Order.

With the exception of Regulatory Alternative VI, the alternatives described in Chapter 6 will not cause impacts characteristic of major rules. This is true because each of Regulatory Alternatives II through V is estimated to entail fifth-year annualized costs of less than $15.4 million, petroleum product price increases of less than .17 percent, and no adverse effects on competition, employment, investment, productivity, innovation, or the United States' balance of trade. For this reason it has been concluded that a Regulatory Impact Analysis is not required.

Section 2(b) of Executive Order 12291 requires that, to the extent permitted by law, regulatory action must not be undertaken unless the potential benefits to society from the regulation outweigh the potential costs to society. A formal benefit-cost study has not been completed due to the costs and time required to complete such an analysis, and because the regulatory alternatives do not constitute a major rule as defined by the Executive Order.

Along with the costs and impacts described in both Chapters 8 and 9, each of the regulatory alternatives will create real benefits to society. Because the alternatives will reduce the rate of emission of VOC to the atmosphere, and because VOC are precursors of photochemical oxidants, the ambient concentrations of such oxidants, particularly ozone, will be affected. The benefits of reduced exposure to ozone will be expressed in terms of the avoidance of the following health effects.

- Human health effects - ozone exposure has been shown to cause increased rates of respiratory symptoms such as coughing, wheezing, sneezing, and short-breath; increased rates of headache, eye irritation and throat irritation; and increases in the number of red blood cells (changes in erthrocytes). One experiment links ozone exposure to human cell damages known as chromosomal aberations.
- Vegetation effects - reduced crop yields as a result of damages to the leaves and/or plants have been shown for several crops including citrus, grapes, and cotton. The reduction in crop yields was shown to be linked to the level and duration of ozone exposure.
- Materials effects - ozone exposure has been shown to accelerate the deterioration of organic materials such as plastics and rubber (elastomers), textile dyes, fibers, and certain paints and coatings.
- Ecosystem effects - continued ozone exposure has been shown to be linked to structural changes of forests such as the disappearance of certain tree species (Ponderosa and Jeffrey pines) and death

of predominant vegetation. Hence ozone causes a stress to the ecosystem.

In addition, the regulatory alternatives are likely to improve the aesthetic and economic value of the environment through the beautification of natural forests and undeveloped land through increased vegetation, increased visibility, reduced incidence of noxious odors, increased length of life for works of art including paintings, sculpture, architecturally important buildings and historic monuments, improved appearance of structures, sculptures, and paintings, and improved productivity of workers.

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*References can be located in Docket Number A-80-44 at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

APPENDIX A

EVOLUTION OF THE BACKGROUND INFORMATION DOCUMENT

APPENDIX A - EVOLUTION OF THE BACKGROUND INFORMATION DOCUMENT

Date	Nature of Action
August 9-12, 1976	Plant visit to Los Angeles Air Pollution Control District and four Los Angeles area petroleum refineries (Fletcher Oil and Refining Company, Atlantic Richfield Watson Petroleum Refinery, Shell Oil Company Wilmington, Champlin Wilmington Refinery) to obtain background information on miscellaneous sources of hydrocarbon emissions from petroleum refineries.
November 3-4, 1976	Meetings with Exxon Company, USA and Shell Oil Company to discuss EPA request for information on hydrocarbon emission sources and controls.
November 8-10, 1976	Plant visits to four New Orleans, Louisiana, petroleum refineries (Murphy, Gulf, Tenneco, and Shell) to obtain background information on miscellaneous sources of hydrocarbon emissions in petroleum refineries.
November 16-17, 1976	Meetings with Standard Oil of California and Union Oil of California to discuss EPA requests for information on hydrocarbon emission sources and controls.
February 8-14, 1977	Emission source testing at Atlantic Richfield Watson Petroleum Refinery, Carson, California, and Newhall Refining Company, Newhall, California.
April 19-20, 1977	Plant vist to "Refinery A," Corpus Christi, Texas, to gather information for Control Techniques Guideline (CTG) documents.
May 1977	First draft CTG, "Control of Hydrocarbons from Miscellaneous Refinery Sources."
April 1978	Second draft CTG, "Control of VOC leaks from Petroleum Refining Equipment."
April 26-28, 1978	Radian/IERL Symposium on refinery emissions, Jekyll Island, Georgia.
June 1978	Publication of final CTG, "Control of Volatile Organic Compound Leaks from Petroleum Refinery Equipment."

June 29, 1978	Plant visit to Phillips Petroleum Company, Sweeny, Texas, to collect information on emissions from benzene-related petroleum refinery operations.
June 30, 1978	Plant visit to Exxon Chemical Company, Baytown, Texas, to collect information on emissions from benzene-related petroleum refinery operations.
July 6, 1978	Plant visit to Sun Petroleum Products Company, Toledo, Ohio, to observe and discuss BTX and THD units.
July 13, 1978	Plant visit to Gulf Oil Refinery, Philadelphia, Pennsylvania, to collect information on emissions from benzene-related petroleum refinery operations (UDEX and toluene dealkylation unit).
July 14, 1978	Plant visit to Sun Petroleum Products Company, Marcus Hook, Pennsylvania, to collect information on emissions from benzene-related petroleum refinery operations.
November 13-17, 1978	Plant visit and emission source testing at Sun Petroleum Products Company, Toledo, Ohio, of BTX and HDA units.
March 5-8, 1979	Plant visit and emission source testing at Phillips Petroleum Company, Sweeny, Texas, refinery.
March 7, 1979	Plant visit to Phillips Petroleum Company, Sweeny, Texas, refinery and NGL Processing Center.
June 20, 1979	Visit to Chevron Company, U.S.A., El Segundo, California, refinery to discuss fugitive VOC emissions.
June 21, 1979	Visit to Atlantic Richfield Company, Carson, California, refinery to discuss fugitive VOC emissions.
November 5-6, 1979	Radian/IERL Symposium on refinery emissions, Austin, Texas.
July 14, 1980	Meeting between EPA and the American Petroleum Institute to discuss pump seal technology, Durham, N.C.

September 18, 1980	Completion of preliminary model units and regulatory alternatives for petroleum refinery VOC fugitive emissions standard development; request for industry review and comment.
September - October 1980	Public comments on preliminary model units and regulatory alternatives.
October 15, 1980	EPA request to industry for information on wastewater separators, cooling towers, and accumulator vessels.
May 4, 1981	Completion of Refinery VOC Fugitives preliminary draft background document and distribution to NAPCTAC, industry, environmental groups, and other interested persons.
June 2-3, 1981	Meeting of the National Air Pollution Control Techniques Advisory Committee to review the refinery VOC fugitive emissions standard, Alexandria, VA.
July 7, 1981	Meeting between EPA and American Petroleum Institute to discuss compressor seal technology, Durham, N.C.
September 1981	Model for evaluating the effects of leak detection and repair (LDAR) programs on fugitive emissions.

APPENDIX B

INDEX TO ENVIRONMENTAL CONSIDERATIONS

This appendix consists of a reference system which is cross-indexed with the October 21, 1974, Federal Register (39 FR 37419) containing the Agency guidelines for the preparation of Environmental Impact Statements. This index can be used to identify sections of the document which contain data and information germane to any portion of the Federal Register guidelines.

APPENDIX B

INDEX TO ENVIRONMENTAL IMPACT CONSIDERATIONS

Agency Guidelines for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Background Information Document
(1) Background and summary of regulatory alternatives	The regulatory alternatives are summarized in Chapter 1, Section 1.1, pages 1-1 through 1-2.
Statutory basis for proposing standards	The statutory basis for the proposed standards is summarized in Chapter 2, Section 2.1, pages 2-1 through 2-4.
Affected industry	A discussion of the industry affected by the regulatory alternatives is presented in Chapter 3, Section 3.1 pages 3-1 through 3-3. Details of the "business/economic" nature of the industry are presented in Chapter 9, pages 9-1 through 9-25.
Affected sources	A description of the sources affected by the regulatory alternatives is presented in Chapter 3, Section 3.2, pages 3-3 through 3-14.
Availability of control technology	A discussion of available emission control techniques is presented in Chapter 4, Section 4.3, pages 4-12 through 4-25.
(2) Environmental, energy, and economic impacts of regulatory alternatives	Various regulatory alternatives are discussed in Chapter 6, Section 6.3, pages 6-4 through 6-7.
Environmental impacts	The environmental impacts of the various regulatory alternatives are presented in Chapter 7, Sections 7.1, 7.2, 7.3 and 7.4, pages 7-1 through 7-9.

Agency Guidelines for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Background Information Document
Energy impacts	The energy impacts of the various regulatory alternatives are discussed in Chapter 7, Section 7-5, pages 7-10 through 7-11.
Cost impacts	Cost impacts of the various regulatory alternatives are discussed in Chapter 8, Section 8.1, pages 8-1 through 8-27.
Economic impacts	The economic impacts of the various regulatory alternatives are presented in Chapter 9, Sections 9.2 and 9.3, pages 9-25 through 9-46.

APPENDIX C
EMISSION SOURCE TEST DATA

APPENDIX C
EMISSION SOURCE TEST DATA

The purpose of Appendix C is to describe testing results used in developing the Background Information Document (BID) for fugitive emissions from the Petroleum Refining Industry. The information contained in this appendix includes a description of the facilities and procedures used in the studies. Section C.1, the results of fugitive emission testing, presents leak frequencies and emission factors for fugitive sources. And, maintenance testing on valve emissions is discussed in Section C.2.

C.1 FUGITIVE EMISSIONS TEST PROGRAMS

C.1.1 Description and Results of a 13-Refinery Study[1]

Data concerning the leak frequencies and emission factors for various fugitive sources were obtained primarily at nine refineries. More complete information for compressor and relief valve emissions was obtained by sampling at four additional refineries. The refineries selected for study comprise a range of sizes and ages and the major petroleum refinery processing units. The type of process units and the number of each studied in the first nine refineries are listed in Table C-1.

In each refinery, sources in six to nine process units were selected for study. The approximate number of sources selected for study and testing in each refinery is listed below:

Valves	250-300
Flanges	100-750
Pump seals	100-125
Compressor seals	10-20
Drains	20-40
Relief valves	20-40

There were normally 500 to 600 sources selected in each refinery.

TABLE C-1. SAMPLED PROCESS UNITS FROM NINE REFINERIES[a]

Refinery process unit	Number of sampled units
Atmospheric distillation	7
Vacuum distillation	4
Thermal operations (coking)	2
Catalytic cracking	5
Catalytic reforming	6
Catalytic hydrocracking	2
Catalytic hydrorefining	2
Catalytic hydrotreating	7
Alkylation	6
Aromatics/isomerization	3
Lube oil manufacture	2
Asphalt manufacture	1
Fuel gas/light-ends processing	11
LPG	2
Sulfur recovery	1
Other	3
TOTAL	64

[a] Reference 1

The distribution of sources among the process units was determined prior to the selection and testing of individual sources. Individual sources were selected from piping and instrumentation diagrams or process flow diagrams before a refinery processing area was entered. Only those preselected sources were screened. In this way, bias based on observation of individual sources was theoretically eliminated.

The sources were screened with portable organic vapor detectors. The principal device used in this study was the J.W. Bacharach Instrument Company "TLV Sniffer" calibrated with hexane. The components were tested on an individual basis, and only those components with concentrations in excess of 200 ppmv were considered for further study. A substantial portion of these leaking sources were enclosed and sampled to determine both the methane and nonmethane emission rates.

Emission factors and leak frequency information generated during this study are given in Table C-2.

C.1.2 Description and Results of Testing at Six U.S. Refineries

A field testing program was conducted to collect data for use in developing an approach for controlling VOC fugitive emissions in the petroleum refining industry. A total of six refineries located throughout the continental U.S. were surveyed to collect emission data and/or maintenance data from individual components of various refinery process units. All units were operating normally throughout the test period. Table C-3 presents a summary of the components tested and the percent of components that were found leaking at or above a specified VOC concentration level.

C.1.2.1 Discussion and Results of Emission Testing at Refineries 1 and 2.[2] Testing was conducted by EPA personnel at refineries 1 and 2 to develop a basic testing approach for VOC leaks from refinery equipment, to obtain comparative test data for procedure selection, and to collect emission data for use in formulating a recommended level of control. Refinery 1 is a medium-sized integrated refinery, and Refinery 2 is a small-sized crude topping refinery.

C.1.2.2 Saturated Gas Plant and Aromatic Extraction Unit at Refinery 3.[4] Individual component surveys were conducted in a saturated gas plant and an aromatic extraction unit at a fairly large integrated refinery in the U.S. Gulf Coast area. Sampling was conducted using a

TABLE C-2. LEAK FREQUENCIES AND EMISSION FACTORS FROM FUGITIVE SOURCES[a]

Equipment type	Percent of sources having screening values ≥10,000 ppmv TLV-Hexane	Confidence interval (%) for percent leaking, ≥10,000 ppmv
Valves		
Gas service	10	6 - 14
Light liquid service	11	8 - 14
Heavy liquid service	0	0 - 1
Pump seals		
Light liquid service	24	19 - 26
Heavy liquid service	2	0 - 5
Compressor seals	36	26 - 44
Pressure relief valves	7	2 - 13
Flanges	0	0 - 1
Open-ended lines	b	b

[a] Reference 1.

[b] No data were available for open-ended lines.

TABLE C-3. SUMMARY OF COMPONENTS TESTED AND PERCENT LEAKING IN SIX REFINERIES

	Number of Components Tested (N) and Percent Leaking (%)							
	Pump seals		Compressor Seals		Valves		Pressure Relief Devices	
Refinery	N	(%)	N	(%)	N	(%)	N	(%)
1[a]	87	(6.9)	2	(0)	201	(9.0)	15	(0)
2[a]	25	(4.0)[f]	0	(0)	28	(0)	0	(0)
3[b]	43	(16.2)	1	(0)	206	(17.5)	0	(0)
4[c]	327	(14.7)	12	(0)	835	(4.0)	0	(0)
5[d]	63	(6.3)[f]	0	(0)	1300	(3.6)	0	(0)
6[e]	190	(21.6)	33	(3.0)	3052	(9.0)	0	(0)
TOTAL	735	(14.6)	48	(2.1)	5622	(7.3)	15	(0)

[a] Reference 2 - Testing was conducted with a Century Systems organic vapor analyzer, Model OVA-108, calibrated with methane, at 5 cm from each source. A leak is defined as greater than or equal to 1,000 ppmv at 5 cm, which is approximately equal to a leak concentration of greater than or equal to 10,000 ppmv at 0 cm (Reference 3).

[b] Reference 4 - Test method and leak definition as in footnote a.

[c] Reference 5 - Test method and leak definition as in footnote a.

[d] Reference 6 - All measurements were performed by traversing the instrument probe at the surface of the potential leak interface (0 cm) with the OVA-108 calibrated with methane. A leak is defined as greater than or equal to 10,000 ppmv.

[e] Reference 7 - Test method and leak definition as in footnote d.

[f] Some pump seals were equipped with dual mechanical seals.

Century Systems Corporation OVA-108 organic vapor analyzer calibrated with methane. Emissions were measured from pump seals, compressor seals, drains, block valves, control valves, and open-ended valves at 5 cm from the potential leak source. Of the total 274 components screened, 36 percent were found to have emissions greater than 100 ppm and 18 percent greater than 1,000 ppm.

It was determined that leak measurement would be conducted at a distance of 5 cm since localized wind and dispersion conditions made measurement at greater distances highly variable.

C.1.2.3 Emission Testing at Refinery 4.[5] Leaks were measured from seals, valves, control valves, and drains of the aromatics extraction (BTX) unit at Refinery 4. A portable hydrocarbon analyzer was used to determine the localized VOC concentration near individual sources and the ambient VOC levels in the unit processing areas. Individual component surveys were conducted at 5 cm from the potential leak source. Of all the equipment tested in the unit, 4.2 percent of the total valves and 15 percent of the pump seals were found to have concentrations greater than 1,000 ppm at 5 cm.

C.1.2.4 Emission Testing at Refinery 5.[6] Refinery 5 is an intermediate-size integrated petroleum refinery located in the North Central United States. Testing was conducted during November 1978 primarily to gather data on leaking components (defined by a VOC concentration of greater than or equal to 10,000 ppmv at 0 cm from the source) in two units that process pure benzene. Individual component surveys were performed using the OVA-108 VOC detector calibrated with methane. The probe was placed at the surface of the potential leak interface (0 cm) to eliminate the wind variability of the measurements, thus improving repeatability.

One of the units tested is a BTX aromatics extraction unit that produces benzene, toluene, and xylene by extraction from refined petroleum feedstocks. The BTX unit was about one year old when tested, and special attention was given during the design and start-up to minimize equipment leaks. Valves were repacked before start-up with two to three times the normal packing. All pumps in benzene service were equipped with dual mechanical seals with a barrier fluid, and all relief valves and process accumulator vessels were tied into the flare header system.

The toluene hydrodealkylation (HDA) unit was originally designed as a naphthalene unit, but was later shutdown and modified to produce benzene. Both BTX and HDA units were equipped with area-monitoring systems.

C.1.2.5 Emissions Testing at Refinery 6.[7] Equipment leak testing was performed at various units in Refinery 6 in March 1979. Six process units were surveyed to determine localized VOC concentrations around individual pieces of equipment by using Model OVA-108 calibrated with methane. Measurements were made at the surface of potential leak sources and recorded as the maximum concentration at the seal interface. The results were used to calculate the frequency of occurrence of various concentration ranges.

C.2 MAINTENANCE TEST PROGRAMS

This section discusses the results of four studies on the effects of maintenance on fugitive emissions from valves. The first two studies were conducted by refinery personnel at the Union Oil Company refinery in Rodeo, California, and the Shell Oil Company refinery in Martinez, California. These programs consisted of maintenance on leaking valves containing fluids with actual vapor pressures greater than 1.5 Reid Vapor Pressure. The third study was conducted at four refineries by EPA. The fourth study, also conducted by EPA, examined maintenance effectiveness at an ethylene production unit. The results and description of each test program are given in the following sections.

C.2.1 Description and Results of the Union Maintenance Study[8]

The Union valve maintenance study consisted of performing undirected maintenance on valves selected from 12 different process units. Maintenance procedures consisted of adjusting the packing gland while the valve was in service. Undirected maintenance consists of performing valve repairs without simultaneous measurement of the effect of repair on the VOC concentration detected. This is in contrast to directed maintenance where emissions are monitored during the repair procedure. With directed maintenance, repair procedures are continued until the VOC concentration detected drops to a specified level or further reduction in the emission level is not possible. Also, maintenance may be curtailed if increasing VOC concentrations result.

The Union data were obtained with a Century Systems Corporation Organic Vapor Analyzer, OVA-108. All measurements were taken at a distance of 1 cm from the seal. Correlations developed by EPA have been used to convert the data from OVA readings taken at 1 centimeter to equivalent TLV readings at the leak interface (TLV-0).[1] This facilitates comparison of data from different studies and allows the estimation of emission rates based on screening values-leak rate correlations.

The results of the Union study are given in Table C-4. Two sets of results are provided; the first includes all repaired valves with before maintenance screening values greater than or equal to 5,300 ppmv (OVA-108), and the second includes valves with before maintenance screening values below 5,300 ppmv (OVA-108). A screening value of 5,300 ppmv, obtained with OVA at 1 cm from the leak interface, is equivalent to a screening value of 10,000 ppmv measured by a Bacharach Instrument Company "TLV Sniffer" directly at the leak interface. The OVA-1 cm readings have been converted to equivalent TLV-0 cm readings because:

1) EPA correlations which estimate leak rates from screening values were developed from TLV-0 cm data.
2) Additional maintenance study data exists in the TLV-0 cm format.
3) Method 21 specifies 0 cm screening procedures.

The results of this study indicate that maintenance on valves with initial screening values above 10,000 ppmv (OVA-108) is much more effective than maintenance on valves leaking at lower rates. In fact, this study indicates that emissions from valves are reduced by an average of 51.8 percent for valves initially over 5,300 ppmv, while valves with lower initial screening values experienced an increase of 30.5 percent.

C.2.2 Description and Results of the Shell Maintenance Study[9]

The Shell maintenance program consisted of two parts. First, valve repairs were performed on 171 leaking valves. In the second part of the program, 162 of these valves were rechecked and additional maintenance was performed. Maintenance consisted of adjusting the packing gland while the valve was in service. The second part of the program was conducted approximately one month after the initial maintenance period. It was not determined whether the maintenance procedures were directed or undirected, based on the information reported by Shell.

TABLE C-4. SUMMARY OF MAINTENANCE STUDY RESULTS FROM THE UNION OIL COMPANY REFINERY IN RODEO, CALIFORNIA[a]

	All valves with initial screening values $\geq 5,300$ ppmv[b]	All valves with initial screening values $<5,300$ ppmv
Number of repairs attempted	133	21
Number of successful repairs (<5,300 ppmv after maintenance)	67	--
Percent successful repairs	50.4	--
Estimated emissions before maintenace, kg/hr	9.72	0.323
Estimated emissions after maintenance, kg/hr	4.69	0.422
Percent reduction in emissions	51.8	-30.5
Number of valves with decreased emissions	124	13
Percent of valves with decreased emissions	93.2	61.9
Number of valves with increased emissions	9	8
Percent of valves with increased emissions	6.8	38.1

[a] Reference 8.

[b] The value 5,300 ppmv, taken with the OVA-108 at 1 cm, generally corresponds to a value of 10,000 ppmv taken with a "TLV Sniffer" at 0 cm.

VOC emissions were measured using the OVA-108, and readings were obtained 1 centimeter from the source. These data have been transformed to TLV-0 cm values as was the Union data. The same methods of data analysis described in Section C.2.1 have been applied to the Shell data. The results of the Shell maintenance study are given in Table C-5.

C.2.3 Description and Results of the EPA Maintenance Study[1]

Repair data were collected on valves located in four refineries. The effects of both directed and undirected maintenance were evaluated. Maintenance consisted of routine operations, such as tightening the packing gland or adding grease. Other data, including valve size and type and process fluid characteristics, were obtained. Screening data were obtained with the Bacharach Instrument Company "TLV Sniffer," and readings were taken as close to the source as possible.

Unlike the Shell and Union studies, emission rates were not based on the screening value correlations. Rather, each valve was sampled to determine emission rates before and after maintenance using techniques developed by EPA during the refinery emission factor study. These values were used to evaluate emissions reduction.

The results of this study are given in Table C-6. Of interest here is a comparison of the emissions reduction for directed and undirected maintenance. The results indicate that directed maintenance is more effective in reducing emissions than is undirected maintenance, particularly for valves with lower initial leak rates. The results showed an increase in total emissions of 32.6 percent for valves with initial screening values less than 10,000 ppmv which were subjected to undirected maintenance. However, this increase is due to a large increase in the emission rate of only one valve.

C.2.4 Description and Results of the Ethylene Unit Maintenance Study at Refinery 6[7]

Maintenance on valves was performed by unit personnel at Refinery 6 (Section C.1.2.5). VOC concentration measurements were made using the OVA-108, and readings were obtained at the closest distance possible to the source. The results of this study are shown in Table C-7. Directed and undirected maintenance procedures were used. The results

Table C-5. SUMMARY OF MAINTENANCE STUDY RESULTS FROM THE SHELL OIL COMPANY REFINERY IN MARTINEZ, CALIFORNIA[a]

	March maintenance		April maintenance	
	All repaired valves with initial screening values ≥5,300 ppmv[b]	All repaired valves with initial screening values <5,300 ppmv	All repaired valves with initial (March) screening values ≥5,300 ppmv	All repaired valves with initial (March) screening values<5,300 ppmv
Number of repairs attempted	161	11	152[d]	11[e]
Number of successful repairs (<5,300 ppmv after maintenance)	105	--	45	--
Percent successful repairs	65.2	--	83.3[f]	--
Estimated emissions before maintenance, kg/hr[c]	11.08	0.159	2.95	0.060
Estimated emissions after maintenance, kg/hr[c]	2.66	0.0	0.421	0.0
Percent reduction in emissions	76.0	100.0	85.7	100.0
Number of valves with decreased emissions	161	11	151	11
Percent of valves with decreased emissions	100.0	100.0	99.3	100.0
Number of valves with increased emissions	0	0	1	0
Percent of valves with increased emissions	0.0	0.0	0.7	0.0

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[a] Reference 9.

[b] The value 5,300 ppmv, taken with the OVA-108 at 1 cm., generally corresponds to a value of 10,000 ppmv taken with a "TLV Sniffer" at 0 cm.

[c] Shell reported the screening value of all valves which measured <3,000 ppmv (<1,500 ppmv-TLV at 0 cm.) as non-leakers. Emissions estimates obtained from emission factors. Reference 10.

[d] Initial screening value for 90 of these valves was <1,500 ppm-TLV at 0 cm.; 54 valves screened ≥5,300 (note nine valves from initial data set not rechecked in April).

[e] Initial screening value for 10 of these valves was <1,500 ppm-TLV at 0 cm.

[f] "Percent successful repairs" is calculated by dividing 45 (number of successful repairs) by 54 (number of valves actually screened ≥5,300 ppmv). See footnote d.

TABLE C-6. SUMMARY OF EPA REFINERY MAINTENANCE STUDY RESULTS[a,b]

	Repaired valves with initial screening values ≥10,000 ppmv		Repaired valves with initial screening values <10,000 ppmv	
	Directed Maintenance	Undirected Maintenance	Directed Maintenance	Undirected Maintenance
Number of valves repaired	9	23	10	16
Number of successful repairs (<10,000 ppmv after maintenance)	8	13	-	-
Percent successful repairs	88.9	56.5	-	-
Measured emissions before maintenance kg/hr	0.107	1.809	0.0332	0.120
Measured emissions after maintenance kg/hr	0.0139	0.318	0.0049	0.159
Percent reduction in emissions	87.0	82.4	85.2	-32.6
Number of valves with decreased emissions	9	21	6	15
Percent of valves with decreased emissions	100.0	91.3	60.0	93.8
Number of valves with increased emissions	0	2	4	1
Percent of valves with increased emissions	0.0	8.7	40.0	6.3

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[a] Reference 1.

[b] TLV 0 cm hexane calibration.

TABLE C-7. MAINTENANCE EFFECTIVENESS ETHYLENE UNIT BLOCK VALVES[a,b]

1. Total number of valves with VOC ≥10,000 ppm from unit survey	121	
2. Total number of valves tested for maintenance effectiveness	46	
% Tested		38%
UNDIRECTED MAINTENANCE		
3. Total number subjected to repair attempts	37	
4. Successful repairs (VOC <10,000 ppm)	22	
% Repaired		59%
Followup DIRECTED MAINTENANCE		
5. Number of valves unrepaired by undirected maintenance subjected to directed maintenance	14	
6. Number repaired by followup directed maintenance	5	
% of unsuccessful repairs by directed maintenance		36%
7. Total number repaired based on undirected maintenance subset (3) above	27	
% Repaired		73%
8. Total number of repairs including leaks not found before initial maintenance	29	
Total % repaired		63%
Total % not repaired		37%

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[a] Reference 7.

[b] OVA-108 0 cm.

show that directed maintenance results in more repairs being successfully completed than when undirected maintenance is used.

C.2.5 Description and Results of EPA-ORD Valve Maintenance Study[11]

A study was undertaken by the EPA Office of Research and Development (ORD) in order to determine the effectiveness of routine (on-line) maintenance in the reduction of fugitive VOC emissions from in-line valves. The overall effectiveness of a leak detection and repair program was examined by studying the immediate emission reduction due to maintenance, the propagation of the leaks after maintenance, and the rate at which new leaks occur for pumps and valves. Testing was conducted at six chemical plants, two for each of three chemical processes (ethylene, cumene, and vinyl acetate production).

It was found that an estimated 71.3 percent (95 percent confidence limits of 54 percent to 88 percent) reduction in fugitive emissions from all valves leaking at various concentrations resulted immediately following maintenance (lasting up to six months). The 30-day rates of occurrence for valves and pumps initially screened at less than 10,000 ppm were 1.3 percent (95 percent confidence interval of 0.7 percent to 2.1 percent) and 5.5 percent (95 percent confidence interval of 2.2 percent to 10 percent), respectively, as shown in Table C-8. In Table C-9, 30-day, 90-day, and 180-day recurrence rate estimates are given along with approximate 95 percent confidence limits. Maintenance of valves in the study averaged about 10 minutes per valve.

C.2.6 Comparison of Maintenance Study Results

A summary of the results of the maintenance programs described in the preceding sections is presented in Table C-10. Generally speaking, the results of these maintenance programs would tend to support the following conclusions:

- A reduction in emissions may be obtained by performing maintenance on valves with screening values above 10,000 ppmv (measured at the source).
- The reduction in emissions due to maintenance of valves with screening values below 10,000 ppmv is not as dramatic and may result in increased emissions.
- Directed maintenance is preferable to undirected maintenance for valve repair.

TABLE C-8. OCCURRENCE RATE ESTIMATES FOR VALVES AND PUMPS BY PROCESS IN EPA-ORD STUDY[a,b]

	30-Day Estimate	95% Confidence Interval	90-Day Estimate	95% Confidence Interval	180-Day Estimate	95% Confidence Interval
VALVES						
Cumene units	1.9	(0.2, 5.9)	5.6	(0.6, 17)	10.8	(1.3, 30)
Ethylene units	2.0	(0.9, 3.6)	6.0	(2.7, 10)	11.6	(5.3, 20)
Vinyl Acetate units	0.3	(0.0, 0.6)	0.8	(0.1, 1.9)	1.5	(0.3, 3.8)
All units	1.3	(0.7, 2.1)	3.8	(2.0, 6.0)	7.4	(4.0, 12)
PUMPS						
Cumene units	5.8	(0.7, 20)	16.3	(2.1, 49)	30.0	(4.2, 74)
Ethylene units	18.4	(2.8, 42)	45.7	(8.2, 80)	70.5	(16, 96)
Vinyl Acetate units	2.8	(0.8, 6.2)	8.1	(2.2, 17)	15.6	(4.4, 32)
All units	5.5	(2.2, 10)	15.7	(6.6, 27)	29.0	(12, 47)

[a] Reference 11.

[b] A leak from a source is defined as having occurred if it initially screened <10,000 ppmv and at some later date screened ≥10,000 ppmv.

TABLE C-9. VALVE LEAK RECURRENCE RATE ESTIMATES[a,b]

	Recurrence Rate Estimate	95% Confidence Limits on the Recurrence Rate Estimate
30-day	17.2%	(5, 37)
90-day	23.9%	(7, 48)
180-day	32.9%	(10, 61)

[a] Reference 11.

[b] Data from 28 maintained valves were examined. Only those valves that screened greater than or equal to 10,000 ppmv immediately before maintenance and screened less than 10,000 ppmv immediately after maintenance were considered having a potential to recur.

TABLE C-10. SUMMARY OF VALVE MAINTENANCE TEST RESULTS

Maintenance Test	Number of Valve Repairs Attempted	Number of Successful Repairs	Percent Repaired
Union[a]	133	67	50.4
Shell[a]			
March 1979	161	105	65.2
April 1979	54	45	83.3
EPA-4 refineries[b]			
Directed[c]	9	8	88.9
Undirected[d]	23	13	56.5
Refinery 6[b]			
Directed and Undirected	46	29	63.0
EPA-ORD[b]			
Directed	97	28	28.9
TOTAL	523	295	56.4

[a] Initial screening value of ≥5,300 ppmv at 1 cm was used to define the population subject to repair. Repair was successful when a valve screened <5,300 ppmv at 1 cm.

[b] Before maintenance screening value of ≥10,000 ppmv at 0 cm was used to define the population subject to repair. Repair was successful when a valve screened <10,000 ppmv at 0 cm.

[c] Directed maintenance refers to a valve maintenance procedure whereby the hydrocarbon detector is utilized during maintenance. The leak is monitored with the instrument until no further reduction of leak is observed or the valve stem rotation is restricted.

[d] Undirected maintenance refers to action by plant personnel in which an assigned worker tightens the valve packing gland with a wrench to further compress the packing material around the valve stem and seat.

The information presented in the tables of Appendix C has been compiled with the objective of placing the data on as consistent a basis as possible. However, some differences were unavoidable and others may have gone unrecognized, due to the limited amount of information concerning the details of methods used in each study. Therefore, care should be exercised before attempting to draw specific quantitative conclusions based on direct comparison of the results of these studies.

C.3 REFERENCES

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*References can be located in Docket Number A-80-44 at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.

APPENDIX D
EMISSION MEASUREMENT
AND CONTINUOUS MONITORING

APPENDIX D - EMISSION MEASUREMENT AND CONTINUOUS MONITORING

D.1 EMISSION MEASUREMENT METHODS

To develop data in support of standards for the control of fugitive emissions, EPA conducted leak surveys at six petroleum refineries and three organic chemical manufacturing plants. The resulting leak determination procedures contained in Reference Method 21 were developed during the course of this test program.

Prior to the first test, available methods for measurement of fugitive leaks were reviewed, with emphasis on methods that would provide data on emission rates from each source. To measure emission rates, each individual piece of equipment must be enclosed in a temporary cover for emission containment. After containment, the leak rate can be determined using concentration change and flow measurements. This procedure has been used in several studies,[1,2] and has been demonstrated to be a feasible method for research purposes. It was not selected for this study because direct measurement of emission rates from leaks is a time-consuming and expensive procedure, and is not feasible or practical for routine testing.

Procedures that yield qualitative or semi-quantitative indications of leak rates were then reviewed. There are essentially two alternatives: leak detection by spraying each component leak source with a soap solution and observing whether or not bubbles were formed; and, the use of a portable analyzer to survey for the presence of increased organic compound concentration in the vicinity of a leak source. Visual, audible, or olefactory inspections are too subjective to be used as indicators of leakage in these applications. The use of a portable analyzer was selected as a basis for the method because it would have been difficult to establish a leak definition based on bubble formation rates. Also, the temperature of the component, physical configuration, and relative movement of parts often interfere with bubble formation.

Once the basic detection principle was selected, it was then necessary to define the procedures for use of the portable analyzer. Prior to performance of the first field test, a procedure was reported that conducted surveys at a distance of 5 cm from the components.[3] This information was used to formulate the test plan for initial testing.[4] In addition, measurements were made at distances of 25 cm and 40 cm on three perpendicular lines around individual sources. Of the three distances, the most repeatable indicator of the presence of a leak was a measurement at 5 cm, with a leak definition concentration of 100 or 1000 ppmv. The localized meteorological conditions affected dispersion significantly at greater distances. Also, it was more difficult to define a leak at greater distances because of the small changes from ambient concentrations observed. Surveys were conducted at 5 cm from the source during the next three facility tests.

The procedure was distributed for comment in a draft control techniques guideline document.[5] Many commentors felt that a measurement distance of 5 cm could not be accurately repeated during screening tests. Since the concentration profile is rapidly changing between 0 and about 10 cm from the source, a small variance from 5 cm could significantly affect the concentration measurement. In response to these comments, the procedures were changed so that measurements were made at the surface of the interface, or essentially 0 cm. This change required that the leak definition level be increased. Additional testing at two refineries and three chemical plants was performed by measuring volatile organic concentrations at the interface surface, except in the case of rotating shaft seals where measurements were made up to 1 cm from the surface for safety reasons.

A complication that this change introduces is that a small mass emission rate leak ("pin-hole leak") can be totally captured by the instrument and a high concentration result will be obtained. This has occurred occasionally in EPA tests, and a solution to this problem has not been found.

The calibration basis for the analyzer was evaluated. It was recognized that there are a number of potential vapor stream components and compositions that can be expected. Since all analyzer types do not respond equally to different compounds, it was necessary to establish a reference calibration material. Based on the expected compounds and the limited information available on instrument response factors, hexane was chosen as the reference calibration gas for EPA test programs. At the 5 cm measurement distance, calibrations were conducted at approximately 100 or 1000 ppmv levels. After the measurement distance was changed, calibrations at 10,000 ppmv levels were required. Commentors pointed out that hexane standards at this concentration were not readily available commercially. Consequently, modifications were incorporated to allow alternate standard preparation procedures or alternate calibration gases in the test method recommended in the Control Techniques Guideline Document for Petroleum Refinery Fugitive Emissions. Since that time, additional studies have begun to develop response factor data for two instrument types. Based on preliminary results,[6] it appears that methane is a more representative reference calibration material at 10,000 ppmv levels. Based on this conclusion, and the fact that methane standards are readily available at the necessary calibration concentrations, the recommended calibration material for this regulation was changed to methane.

The alternative of specifying a different calibration material for each type stream and normalization factors for each instrument type was not intensively investigated. There are at least four instrument types available that might be used in this procedure, and there are a large number of potential stream compositions possible. The amount of prior knowledge necessary to develop and subsequently use such factors would make the interpretation of results prohibitively complicated. Based on EPA test results, the number of concentration measurements in the range where a variability of two or three would change the decision as to whether or not a leak exists is small in comparison to the total number of potential leak sources.

An alternative approach to leak detection was evaluated by EPA during field testing. The approach used was an area survey, or walkthrough, using a portable analyzer. The unit area was surveyed by walking through the unit positioning the instrument probe within 1 meter of all valves and pumps. The concentration readings were recorded on a portable strip chart recorder. After completion of the walkthrough, the local wind conditions were used with the chart data to locate the approximate source of any increased ambient concentrations. This procedure was found to yield mixed results. In some cases, the majority of leaks located by individual component testing could be located by walkthrough surveys. In other tests, prevailing dispersion conditions and local elevated ambient concentrations complicated or prevented the interpretation of the results. Additionally, it was not possible to develop a general criteria specifying how much of an ambient increase at a distance of 1 meter is indicative of a 10,000 ppm concentration at the leak source. Because of the potential variability in results from site to site, routine walkthrough surveys were not selected as a reference or alternate test procedure.

D.2 CONTINUOUS MONITORING SYSTEMS AND DEVICES

Since the leak determination procedure is not a typical emission measurement technique, there are no continuous monitoring approaches that are directly applicable. Continual surveillance is achieved by repeated monitoring or screening of all affected potential leak sources. A continuous monitoring system or device could serve as an indicator that a leak has developed between inspection intervals. EPA performed a limited evaluation of fixed-point monitoring systems for their effectiveness in leak detection. The systems consisted of both remote sensing devices with a central readout and a central analyzer system (gas chromatograph) with remotely collected samples. The results of these tests indicated that fixed point systems were not capable of sensing all leaks that were found by individual component testing. This is to be expected since these systems are significantly affected by local dispersion conditions and would require either many individual point locations, or very low detection sensitivities in order to achieve similar results to those obtained using an individual component survey.

It is recommended that fixed-point monitoring systems not be required since general specifications cannot be formulated to assure equivalent results, and each installation would have to be evaluated individually.

D.3 PERFORMANCE TEST METHOD

The recommended VOC fugitive emission detection procedure is Reference Method 21. This method incorporates the use of a portable analyzer to detect the presence of volatile organic vapors at the surface of the interface where direct leakage to atmosphere could occur. The approach of this technique assumes that if an organic leak exists, there will be an increased vapor concentration in the vicinity of the leak, and that the measured concentration is generally proportional to the mass emission rate of the organic compound.

An additional procedure provided in Reference Method 21 is for the determination of "no detectable emissions." The portable VOC analyzer is used to determine the local ambient VOC concentration in the vicinity of the source to be evaluated, and then a measurement is made at the surface of the potential leak interface. If a concentration change of less than 2 percent of the leak definition is observed, then a "no detectable emissions" condition exists. The definition of 2 percent of the leak definition was selected based on the readability of a meter scale graduated in 2 percent increments from 0 to 100 percent of scale, and not necessarily on the performance of emission sources. "No detectable emissions" would exist when the observed concentration change between local ambient and leak interface surface measurements is less than 200 ppmv.

Reference Method 21 does not include a specification of the instrument calibration basis or a definition of a leak in terms of concentration. Based on the results of EPA field tests and laboratory studies, methane is recommended as the reference calibration basis for VOC fugitive emission sources in the petroleum refining industry.

There are at least four types of detection principles currently available in commercial portable instruments. These are flame ionization, catalytic oxidation, infrared absorption (NDIR), and photoionization. Two types (flame ionization and catalytic oxidation) are known to be available in Factory Mutual certified versions for use in hazardous atmospheres.

The recommended test procedure includes a set of design and operating specifications and evaluation procedures by which an analyzer's performance can be evaluated. These parameters were selected based on the allowable tolerances for data collection, and not on EPA evaluations of the performance of individual instruments. Based on manufacturers' literature specifications and reported test results,[7] commercially available analyzers can meet these requirements.

The estimated purchase cost for an analyzer ranges from about $1,000 to $5,000 depending on the type and optional equipment. The cost of an annual monitoring program per unit, including semiannual instrument tests and reporting is estimated to be from $3,000 to $4,500. This estimate is based on EPA contractor costs experienced during previous test programs. Performance of monitoring by plant personnel may result in lower costs. The above estimates do not include any costs associated with leak repair after detection.

D.4 REFERENCES

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APPENDIX E

REFINERY CAPACITY AND MODEL UNIT GROWTH PROJECTIONS

E.1 REFINERY CAPACITY

Table E-1 provides a listing of total refinery capacity in the United States and its territories as of January 1, 1980. For purposes of this summary the refinery is defined as a system of process units, at least one of which has the capability to process crude oil. The table notes for each refinery its location, company, and calendar day crude oil distillation capacity. It should be noted that one cubic meter (m^3) is equivalent to approximately 6.29 barrels.

E.2 MODEL UNIT GROWTH PROJECTIONS

As noted in Table E-2 it has been projected that up to and including the year 1986, 100 new units and 182 modification/reconstructions of existing process units will be subject to the implementation of a regulatory alternative. The following discussion provides a brief review of the causes and nature of growth in the refinery industry, and summarizes the method used to estimate the number of units that may be affected by this standard.

Although the demand for petroleum products in many applications is projected to fall (see Section 9.1.3.1), the construction of new, and reconstruction/modification of existing, refinery units will continue over the forecast period (1981-1986). This apparent conflict is a direct result of the need for existing refineries to cope with the shifting supply and demand patterns present in the current market.

With regard to supply, the decreasing availability of light, low-sulfur crude requires that refineries upgrade present capacity, providing the flexibility needed to process a wider range of various quality crudes. In particular, desulfurization capacity will be needed as fewer "sweet" crudes are available. In addition, the need to meet higher octane demands of unleaded gasoline, will require the upgrading of capacity to produce higher octane blending stocks. In short, refinery modernization will continue regardless of overall demand reductions.

The rapid expansion in small refinery construction, observed during the 1970's, is not anticipated to continue into the 1980's. This is true because the decontrol of domestic crude production has eliminated the subsidies extended to small refiners under the DOE Entitlements Program. Furthermore, the small refiners may be more adversely impacted by the changes in crude supplies noted above. This is so since small refineries, in general, do not

Table E-1. CRUDE DISTILLATION CAPACITY BY REFINERY BY STATE UNITED STATES AND UNITED STATES TERRITORIES January 1, 1980[a]

Company and Refining Location	Crude Capacity m^3/cd
ALABAMA	
Hunt Oil Co. - Tuscaloosa	5,556
Louisianna Land & Exploration Co. - Mobile	6,566
Marion Corp. - Theodore	3,291
Mobile Bay Refining Co. - Chickasaw	4,467
Vulcan Asphalt Refining Co. - Cordova	1,556
Warrior Asphalt Co. of Alabama Inc. - Holt	1,556
ALASKA	
Atlantic Richfield Co. - North Slope	2,258
Chevron U.S.A. Inc. - Kenai	3,498
Earth Resources Co. of Alaska - North Pole	5,028
Tesoro Petroleum Corp. - Kenai	7,711
ARIZONA	
Arizona Fuels Corp. - Fredonia	954
ARKANSAS	
Berry Petroleum Co. - Stephens	636
Cross Oil & Refining Co. of Arkansas - Smackover	1,463
MacMillan Ring-Free Oil Co. Inc. - Norphlet	700
Tosco Corp. - El Dorado	7,472
CALIFORNIA	
Anchor Refining Co. - McKittrick	1,590
Atlantic Richfield Co. - Carson	28,617
Beacon Oil Co. - Hanford	1,876
Champlin Petroleum Co. - Wilmington	4,833
Chevron U.S.A. Inc. - Bakersfield	4,134
Chevron U.S.A. - El Segundo	62,003 2,385[b]
Chevron U.S.A. - Richmond	46,741 11,288[b]
Coastal Petroleum Co. - Paloma	1,622
Conoco - Paramount	7,393
Conoco - Santa Maria	1,510
Demenno Resources - Compton	2,385
ECO Petroleum Inc. - Long Beach	1,749
Edgington Oil Co. Inc. - Long Beach	4,690
Exxon Co. U.S.A. - Benecia	16,216
Fletcher Oil & Refining Co. - Carson	4,690
Getty Refining & Marketing Co. - Bakersfield	3,577
Gibson Oil & Refining Co. - Bakersfield	731
Golden Eagle Regining Co. Inc. - Carson	2,571
Gulf Oil Co. U.S. - Santa Fe Springs	8,188
Huntway Refining Co. - Wilmington	859
Kern County Refinery Inc. - Bakersfield	3,339
Lunday-Thagard Oil Co. - South Gate	1,590
MacMillan Ring-Free Oil Co. Inc. - Long Beach	1,940
Marlex Oil & Refining Inc. - Long Beach	3,021
Mobil Oil Corp. - Torrance	19,634
Newhall Refining Co. Inc. - Newhall	2,798
Oxnard Refinery - Oxnard	636
Pacific Refining Co. Inc. - Hercules	13,514
Powerline Oil Co. - Santa Fe Springs	7,014
Quad Refining Corp. - Bakersfield	1,113
Road Oil Sales Inc. - Bakersfield	477
Sabre Refining Inc. - Bakersfield	1,192
San Joaquin Refining Co. - Bakersfield	3,180
Shell Oil Co. - Martinez	14,531 2,003[b]
Shell Oil Co. - Wilmington	14,785
Sunland Refining Corp. - Bakersfield	1,272 318[b]

Table E-1. (Continued)

Company and Refining Location	Crude Capacity m^3/cd
Texaco Inc. - Wilmington	11,924
Tosco Corp. - Avon	20,032 1,749[b]
Tosco Corp. - Bakersfield	6,359
U.S.A. Petrochem Corp. - Ventura	3,816
Union Oil Co. of California - Aroyo Grande	6,518
Union Oil Co. of California - Rodeo	11,129
Union Oil Co. of California - Wilmington	17,170
West Coast Oil Co. - Oildale	3,021
Witco Chemical Corp. - Oildale	1,510
COLORADO	
Asamera Oil Inc. - Commerce City	3,498
Conoco - Commerce City	1,606
Gary Refining Co. - Fruita	2,083
DELAWARE	
Getty Refining & Marketing Co. - Delaware City	22,258
FLORIDA	
Manatee Energy Co. - Manatee	4,515
Seminole Refining Inc. - St. Marks	2,067
GEORGIA	
Amoco Oil Co. - Savannah	2,862
Young Refining Corp. - Douglasville	509
HAWAII	
Chevron U.S.A. Inc. - Honolulu	7,313
Hawaiian Independent Refining Inc. - Ewa Beach	10,795
ILLINOIS	
Amoco Oil Co. - Wood River	17,170
Bi-Petro Inc. - Pana	986[b]
Clark Oil & Refining Corp. - Blue Island	10,572
Clark Oil & Refining Corp. - Hartford	10,111
Dillman Oil Recovery Inc. - Robinson	175
Energy Development Inc. - Crossville	111
Marathon Oil Co. - Robinson	31,002
Mobil Oil Corp. - Joliet	28,617
Shell Oil Co. - Wood River	44,992
Texaco Inc. - Lawrenceville	13,355
Texaco Inc. - Lockport	11,447
Union Oil Co. of California - Lemont	24,006
Wireback Oil Co. - Plymouth	286
Yetter Oil Co. - Colmar	159
INDIANA	
Amoco Oil Co. - Whiting	60,413
Energy Cooperative Inc. - East Chicago	20,032
Gladieux Refinery Inc. - Fort Wayne	1,940
Indiana Farm Bureau Coop. Ass. Inc. - Mt. Vernon	3,275
Industrial Fuel & Asphalt of Ind. Inc. - Hammond	1,183
Kentucky Oil & Refining Co. - Troy	238
Laketon Asphalt Refining Co. - Laketon	1,351
Princeton Refining Inc. - Princeton	795[b]
Rock Island Refining Corp. - Indianapolis	6,868
KANSAS	
CRA, Inc. - Coffeyville	8,983
CRA, Inc. - Phillipsburg	4,197
Derby Refining Co. - North Wichita	4,449
E-Z Serv Refining Inc. - Shallow Water	1,510
Getty Refining & Marketng Co. - El Dorado	12,810
Mid-America Refining Co. Inc. - Chanute	556
Mobil Oil Corp. - Augusta	7,949

Table E-1. (Continued)

Company and Refining Location	Crude Capacity m^3/cd
KANSAS (Continued)	
National Coop. Refinery Ass. - McPherson	8,609
Pester Refining Co. - El Dorado	4,054
Phillips Petroleum Co. - Kansas City	12,719
Total Petroleum Inc. - Arkansas City	6,757
KENTUCKY	
Ashland Oil Inc. - Catlettsburg	33,927
Ashland Oil Inc. - Louisville	4,006
Kentucky Oil & Refining Co. - Betsy Lane	477
Somerset Refinery Inc. - Somerset	795
LOUISIANA (Inland)	
Atlas Processing Co. - Shreveport	7,154
Bayou State Oil Corp. - Hosston	795
	143[b]
Calumet Refining Co. - Princeton	313
Claiborne Gasoline Co. - Lisbon	1,033
Cotton Valley Solvents Co. - Cotton Valley	1,272
Kerr-McGee Corp. - Dubach	1,749
Port Petroleum Inc. - Stonewall	286
Schulze Processing Inc. - Tallulah	127
LOUISIANA (Gulf)	
Bruin Refining Inc. - St. James	2,941
Calcasieu Refining Ltd. - Lake Charles	2,528
Canal Refining Co. - Church Point	1,192
Cities Service Co. - Lake Charles	46,264
Conoco - Egan	1,431
	477[b]
Conoco - Westlake	13,831
Evangeline Refining Co. Inc. - Jennings	509
Exxon Co. U.S.A. - Baton Rouge	79,491
Good Hope Industries Inc. - Good Hope	13,052
Gulf Oil Co. U.S. - Belle Chasse	31,145
Gulf Oil Co. U.S. - Venice	4,563
Hill Petroleum Co. - Krotz Springs	1,590
International Processors - St. Rose	4,547
LaJet Inc. - St. James	3,180
Lake Charles Refining Co. - Lake Charles	4,769
Mallard Resources Inc. - Gueydon	1,192
Marathon Oil Co. - Garyville	40,541
Mt. Airy Refining Co. - Mt. Airy	3,657
Murphy Oil Corp. - Meraux	14,706
Placid Refining Co. - Port Allen	5,723
Shell Oil Co. - Norco	36,566
Shepard Oil Co. - Jennings	1,590
Slapco - Mermentau	2,305
Sooner Refining Co. - Darrow	859
T&S Refining Inc. - Jennings	1,622
Tenneco Oil Co. - Chalmette	18,124
Texaco Inc. - Convent	22,258
MARYLAND	
Amoco Oil Co. - Baltimore	2,385
Chevron U.S.A. Inc. - Baltimore	2,146[b]
MICHIGAN	
Consumers Power Co. - Marysville	5,986[b]
Crystal Refining Co. - Carson City	636
Dow Chemical U.S.A. - Bay City	668
	477[b]
Lakeside Refining Co. - Kalamazoo	890
Marathon Oil Co. - Detroit	10,890
Texas American Petrochemicals Inc. - West Branch	1,828
Total Petroleum Inc. - Alma	6,359

Company and Refining Location	Crude Capacity m^3/cd
MINNESOTA	
Ashland Oil Inc. - St. Paul Park	10,675
Conoco - Wrenshall	3,736
Koch Refining Co. - Rosemount	20,238
MISSISSIPPI	
Amerada Hess Corp. - Purvis	4,769
Chevron U.S.A. Inc. - Pascagoula	44,515
Ergon Refining Inc. - Vicksburg	1,876
Southland Oil Co. - Lumberton	922
Southland Oil Co. - Sandersville	1,749
Southland Oil Co. - Yazoo City	668
Vicksburg Refining Inc. - Vicksburg	1,256
MISSOURI	
Amoco Oil Co. - Sugar Creek	16,534
MONTANA	
Conoco - Billings	8,347
Exxon Co. U.S.A. - Billings	7,154
Farmers Union Central Exchange Inc. - Laurel	6,622
Kenco Refining Inc. - Wolf Point	747
Phillips Petroleum Co. - Great Falls	954
Westco Refining Co. - Cut Bank	843
NEBRASKA	
CRA, Inc. - Scottsbluff	890
NEVADA	
Nevada Refining Co. - Tonopah	715
NEW HAMPSHIRE	
ATC Petroleum Inc. - Newington	2,130
NEW JERSEY	
Amerada Hess Corp. - Port Reading	10,811[b]
Chevron U.S.A. Inc. - Perth Amboy	26,709
Exxon Co. U.S.A. - Linden	46,105
Mobil Oil Corp. - Paulsboro	15,580
Seaview Petroleum Co. - Paulsboro	7,059
Texaco Inc. - Westville	14,308
NEW MEXICO	
Caribou-Four Corners Oil Co. - Farmington	397
Giant Industries Inc. - Farmington	2,146
Navajo Refining Co. - Artesia	4,758
Plateau Inc. - Bloomfield	2,671
Shell Oil Co. - Gallup	2,862
Southern Union Refining Co. - Lovington	5,723
Southern Union Refining Co. - Monument	127
	731[b]
Thriftway Oil Co. - Bloomfield	970
NEW YORK	
Ashland Oil Inc. - Buffalo	10,175
Cibro Petroleum Products Inc. - Albany	5,390
Mobil Oil Corp. - Buffalo	6,836
NORTH CAROLINA	
ATC Petroleum Inc. - Wilmington	1,892
NORTH DAKOTA	
Amoco Oil Co. - Mandan	8,903
Northland Oil and Refining Co. - Dickinson	795
Westland Oil Co. - Williston	741

Company and Refining Location	Crude Capacity m^3/cd
OHIO	
Ashland Oil Inc. - Canton	10,493
Ashland Oil Inc. - Findlay	3,243[b]
Gulf Oil Co. U.S. - Cleves	6,948
Gulf Oil Co. U.S. - Toledo	7,997
Standard Oil Co. of Ohio - Lima	26,709
Standard Oil Co. of Ohio - Toledo	19,078
Sun Co. Inc. - Toledo	19,873
OKLAHOMA	
Allied Materials Corp. - Stroud	1,097
Champlin Petroleum Co. - Enid	8,553
Conoco - Ponca City	21,304
Hudson Refining Co. Inc. - Cushing	3,100
Kerr-McGee Corp. - Wynnewood	7,949
OKC Corp. - Okmulgee	3,975
Oklahoma Refining Co. - Cyril	2,480
Sun Co. Inc. - Duncan	7,711
Sun Co. Inc. - Tulsa	14,070
Texaco Inc. - Tulsa	7,949
Tonkawa Refining Co. - Arnett	1,272
Vickers Petroleum Corp. - Ardmore	10,191
OREGON	
Chevron U.S.A. Inc. - Portland	2,385
PENNSYLVANIA	
Ashland Oil Inc. - Freedom	1,081
Atlantic Richfield Co. - Philadelphia	29,412
BP Oil Corp. - Marcus Hook	26,073
Gulf Oil Co. U.S. - Philadelphia	32,798
Pennzoil Co. - Rouseville	2,321
Quaker State Oil Refining Corp. - Emlenton	525
Quaker State Oil Refining Corp. - Smethport	1,033
Sun Co. Inc. - Marcus Hook	26,232
United Refining Co. - Warren	6,359
Witco Chemical Corp. - Bradford	1,145
TENNESSEE	
Delta Refining Co. - Memphis	6,757
TEXAS (Inland)	
Adobe Refining Co. - La Blanca	795
American Petrofina Co. of Texas - Big Spring	9,539
Chevron U.S.A. Inc. - El Paso	12,083
Diamond Shamrock Corp. - Sunray	11,566
Dorchester Refining Co. - Mount Pleasant	4,213
Flint Chemical Co. - San Antonio	191
Howell Hydrocarbons Inc. - San Antonio	954
La Gloria Oil & Gas Co. - Tyler	795
Longview Refining Co. - Longview	1,431
Petrolite Corp. - Kilgore	159
Phillips Petroleum Co. - Borger	15,421
Pioneer Refining Ltd. - Nixon	843
Pride Refining Inc. - Abilene	5,803
Quitman Refining Co. - Quitman	1,049
Rancho Refining Co. Inc. - Donna	556
Sector Refining Inc. - Palestine	636
	954[b]
Shell Oil Co. - Odessa	5,087
Sigmore Refining Corp. - Three Rivers	3,498
Tesoro Petroleum Corp. - Carrizo Springs	4,149
Texaco Inc. - Amarillo	3,180
Texaco Inc. - El Paso	2,703
Texas Asphat & Refining Co. - Euless	4,658
Thriftway Oil Co. - Graham	382
Wickett Refining Co. - Wickett	1,272[b]
Winston Refining Co. - Fort Worth	3,084

Table E-1. (Continued)

Company and Refining Location	Crude Capacity m^3/cd
TEXAS (Gulf)	
American Petrofina Co. of Texas - Port Arthur	14,308
Amoco Oil Co. - Texas City	65,978
Atlantic Richfield Co. - Houston	54,849
Carbonit Refinery Inc. - Hearne	1,590
Champlin Petroleum Co. - Corpus Christi	24,642
Charter International Oil Co. - Houston	10,334
Coastal States Petroleum Co. - Corpus Christi	29,412
Copano Refining Co. - Ingleside	1,510
Crown Central Petroleum Corp. - Pasadena	15,898
Eddy Refining Co. - Houston	517
Erickson Refining Corp. - Port Neches	4,769
Exxon Co. U.S.A. - Baytown	101,749
Friendswood Refining Co. - Friendswood	1,987
Gulf Energy Refining Corp. - Brownsville	1,510
Gulf Oil Co. U.S. - Port Arthur	53,386
Gulf States Oil & Refining Co. - Corpus Christi	1,590
Independent Refining Corp. - Winnie	1,749
Marathon Oil Co. - Texas City	11,049
Mobil Oil Corp. - Beaumont	42,512 9,157[b]
Monsanto Co. - Alvin/Teas City	1,351
Nueces Petrochemical Co. - Corpus Christi	5,564
Petraco-Valley Oil & Refining Co. - Brownsville	1,955
Phillips Petroleum Co. - Sweeny	34,658
Placid Refining Co. - Mont Belvieu	1,971
Saber Refining Co. - Corpus Christi	3,577
Sentry Refining Inc. - Corpus Christi	1,590
Shell Oil Co. - Deer Park	45,310
South Hampton Co. - Silsbee	3,259
Southwestern Refining Co. Inc. - Corpus Christi	19,078
Sun Co. Inc. - Corpus Christi	9,134
Texaco Inc. - Port Arthur	58,029
Texaco Inc. - Port Neches	6,200 1,272[b]
Texas City Refining Inc. - Texas City	20,143
Tipperary Refining Co. - Ingleside	1,033
Uni Oil Co. - Ingleside	6,264
Union Oil Co. of California - Nederland	19,078
UTAH	
Amoco Oil Co. - Salt Lake City	6,200
Caribou-Four Corners Oil Co. - Woods Cross	1,192
Chevron U.S.A. Inc. - Salt Lake City	7,154
Husky Oil Co. - North Salt Lake	3,975
Morrison Petroleum Co. - Woods Cross	1,035
Phillips Petroleum Co. - Woods Cross	3,816
Plateau Inc. - Roosevelt	1,192
Western Refining Co. - Woods Cross	1,987
VIRGINIA	
Amoco Oil Co. - Yorktown	8,426
WASHINGTON	
Atlantic Richfield Co. - Ferndale	17,488
Chevron U.S.A. Inc. - Richmond Beach	874
Mobil Oil Corp. - Ferndale	11,367
Shell Oil Co. - Anacortes	14,467
Sound Refining Inc. - Tacoma	1,227
Texaco Inc. - Anacortes	12,401
U.S. Oil & Refining Co. - Tacoma	3,402
United Independent Oil Co. - Tacoma	116
WEST VIRGINIA	
Elk Refining Co. - Falling Rock	890
Quaker State Oil Refining Corp. - Newell	1,542
Quaker State Oil Refining Corp. - St. Mary's	763

Table E-1. (Continued)

Company and Refining Location	Crude Capacity m^3/cd
WISCONSIN	
Murphy Oil Corp. - Superior	6,359
WYOMING	
Amoco Oil Co. - Casper	7,631
C&H Refinery Inc. - Lusk	30
Glacier Park Co. - Osage	638
Glenrock Refinery Inc. - Glenrock	511
Husky Oil Co. - Cheyenne	4,573
	3,659[b]
Husky Oil Co. - Cody	1,828
Little America Refining Co. - Casper	3,895
Mountaineer Refining Co. Inc. - La Barge	24
	87[b]
Sage Creek Refining Co. Inc. - Cowley	95
Silver Eagle Refining Co. - La Barge	318
Sinclair Oil Corp. - Sinclair	11,129
Southwestern Refining Co. - La Barge	175
Texaco Inc. - Casper	3,339
Wyoming Refining Co. - Newcastle	1,669
PUERTO RICO	
Caribbean Gulf Refining Corp. - Bayamon	5,405
Commonwealth Oil Refining Co. Inc. - Penuelas	15,103
	7,711[b]
Peerless Petrochemicals Inc. - Ponce	1,590
Sun Co. Inc. - Yabucoa	13,196
VIRGIN ISLANDS	
Amerada Hess Corp. - St. Croix	111,288
GUAM	
Guam Oil & Refining Corp. - Agana	6,979
TOTAL	3,031,863

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[a] U.S. Department of Energy. Energy Information Administration. Petroleum Refineries in the United States and U.S. Territories. January 1, 1980. DOE/EIA-0111(80).

[b] Capacity shutdown but capable of being placed in operation within 90 days.

Table E-2. REFINERY PROCESS UNIT GROWTH PROJECTIONS (1981-86)
(Number of Units)

Model Unit	Unit Type	New Units		Modifications/Reconstructions	
		Number	Total	Number	Total
A	Hydrotreating	34	49	35	47
	Isomerization	1		2	
	Lube Oil	2		4	
	Asphalt	2		4	
	Hydrogen	10		2	
B	Alkylation	3	27	3	79
	Reforming	13		38	
	Thermal Cracking	5		15	
	Vacuum Distillation	6		23	
C	Crude Distillation	17	24	37	56
	Catalytic Cracking	7		19	
			100		182

have the downstream processing capabilities needed to maintain quality output from heavier crudes. All of the conditions and factors noted above have been considered in the projection of affected units as described below.

The projections have been made by counting, for each process unit type, the number of new unit constructions and existing unit reconstructions and modifications, known to have occurred over the five-year period 1976-1980. This was accomplished through examination of the "Worldwide Construction" issues of the Oil and Gas Journal for the appropriate years. While new unit construction is specifically noted in the reports reviewed, expansions in output have been counted as unit modifications and reconstructions since increases in unit capacity are often achieved by increasing the number of equipment components (i.e., valves, pumps, etc.) comprising a unit. Therefore, since such components are the sources of fugitive VOC emissions, unit capacity increases could entail increased emissions and thus fall subject to new source designation through modification.

The uncertainty of continued Federal support of small refiners requires an adjustment to the projection method, thus recognizing that the recent rapid growth of small refineries is unlikely to continue. This adjustment has been accomplished by counting only those constructions and modifications that have occured at existing refineries with crude distillation capacity in excess of 2,226 m^3 per calendar day. This cut-off point was chosen since it represents the average size of those small refineries built during the period 1974-1980 under protective regulations such as the entitlements program.

The results of the model unit growth projections, made according to the method described above, are summarized in Table E-2. These projections serve as the basis for the projection of environmental and economic impacts presented in Chapters 7 and 9, respectively.

APPENDIX F

EVALUATION OF THE EFFECTS OF LEAK DETECTION AND REPAIR ON FUGITIVE EMISSIONS USING THE LDAR MODEL

F.0 EVALUATION OF THE EFFECTS OF LEAK DETECTION AND REPAIR ON FUGITIVE EMISSIONS USING THE LDAR MODEL

The purpose of Appendix F is to present a mathematical model for evaluating leak detection and repair programs (LDAR model) and to compare the impacts determined by this model with the results of the impact analyses in Chapters 7, 8, and 9. The LDAR model is an empirical approach which incorporates recently available leak occurrence and recurrence data and emission reduction data regarding the effectiveness of simple on-line repair of leaking sources.[1] Whereas, the leak detection and repair program impacts presented in Chapters 7, 8, and 9 are determined through derived controlled emission correction factors (ABCD Model) which are based in part upon engineering judgment.

F.1 LDAR MODEL

The LDAR model is based on the premise that all sources at any given time are in one of four categories:

1) Non-leaking sources (sources screening, or found to be emitting VOC, less than the action level of 10,000 ppmv);

2) Leaking sources (sources screening equal to or greater than the action level);

3) Leaking sources which cannot be repaired on-line (screening equal to or greater than the action level) that are awaiting a shutdown, or process unit turnaround, for repair; and

4) Repaired sources with early leak recurrence.

There are also four basic components to the LDAR model:

1) Screening of all sources except those in Category 3, above;

2) Maintenance of screened sources in Categories 2 and 4, above, in order to reduce emissions to less than 10,000 ppmv;

3) Rescreening of repaired sources;

4) Process unit turnaround during which maintenance is performed for sources in Categories 2, 3, and 4, above. Figure F-1 shows a schematic diagram of the LDAR model.

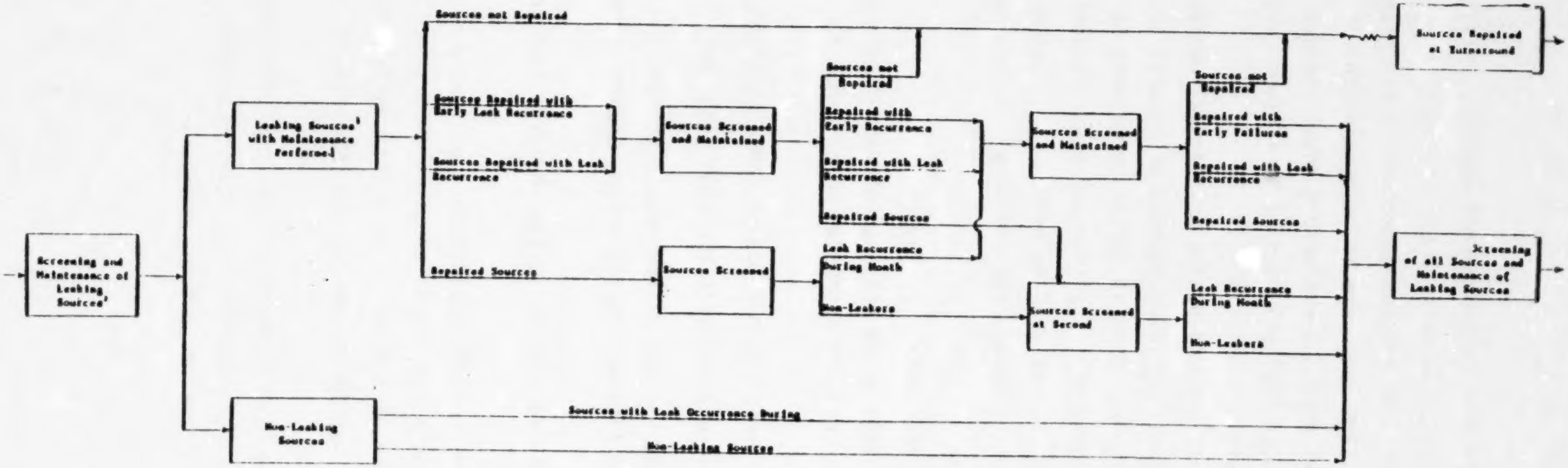
Screening and Maintenance of Leaking Sources[2]
Leaking Sources[1] with Maintenance Performed
Non-Leaking Sources
Sources not Repaired
Sources Repaired with Early Leak Recurrence
Sources Repaired with Leak Recurrence
Repaired Sources
Sources Screened and Maintained
Sources Screened
Sources not Repaired
Repaired with Early Recurrence
Repaired with Leak Recurrence
Repaired Sources
Leak Recurrence During Month
Non-Leakers
Sources Screened and Maintained
Sources Screened at Second
Sources not Repaired
Repaired with Early Failures
Repaired with Leak Recurrence
Repaired Sources
Leak Recurrence During Month
Non-Leakers
Sources with Leak Occurrence During
Non-Leaking Sources
Sources Repaired at Turnaround
Screening of all Sources and Maintenance of Leaking Sources

Figure F-1. SCHEMATIC DIAGRAM OF THE LDAR MODEL

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[1] Leaking sources include all sources which had leak recurrence, had experienced early failures, or had leak occurrence and remained leakers

[2] Except sources for which attempted maintenance was not successful.

Since there are only four categories of sources, only four "leak rates" apply to all sources. In fact, there are only three distinct leak rates, since the repaired sources experiencing early leak recurrence are assumed to have the same leak rate as sources which were unsuccessfully repaired. The LDAR model does not evaluate gradual changes in leak rates over time but assumes that all sources in a given category have the same average leak rate.

The LDAR model is implemented by the Statistical Analysis System (SAS) computer program enabling investigation of several leak detection and repair program scenarios. General inputs pertaining to the leak detection and repair program may vary (for example, frequency of inspection, repairs, and process unit turnarounds). Further, input characteristics of the emission sources may vary. Inputs required in the latter group include:

1) The fraction of sources initially leaking;

2) The fraction of sources which become leakers during a period;

3) The fraction of sources with attempted maintenance for which repair was successful;

4) The emission reductions from successful and unsuccessful repair.

Other assumptions associated with the LDAR model are:

1) All repairs occur at the end of the repair period; the effects associated with the time interval during which repairs occur are negligible;

2) Unsuccessfully repaired sources instantaneously fall into the unrepaired category;

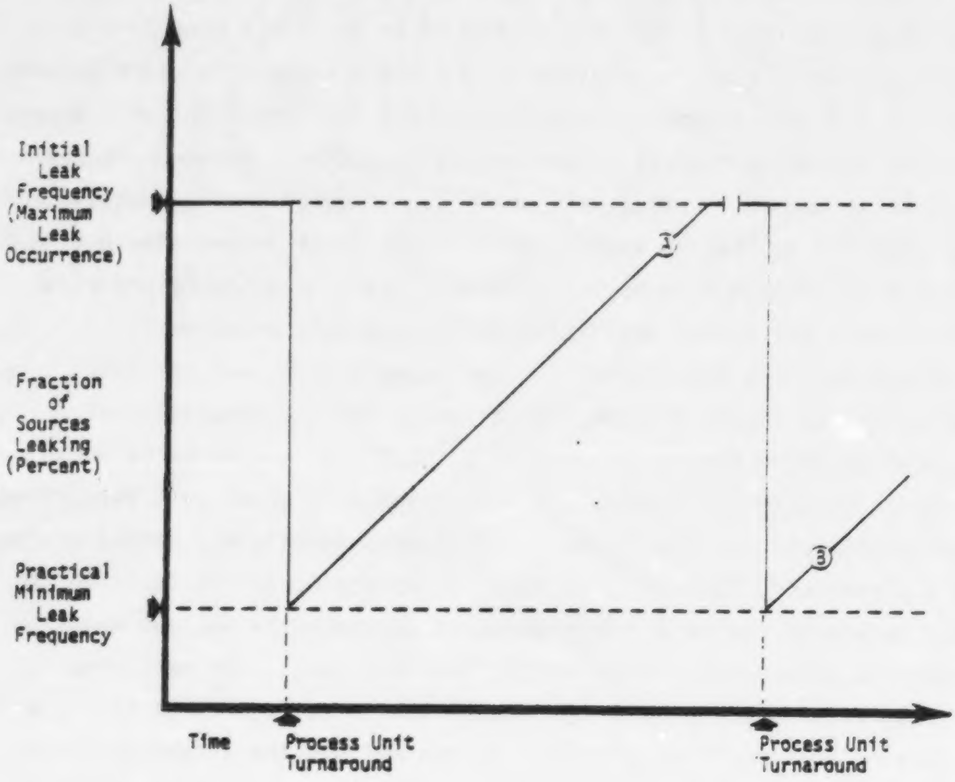
3) Leaks other than unsuccessful maintenance and early recurrences occur at a linear rate with time during a given inspection period;

4) A process unit turnaround essentially occurs instantaneously at the end of a turnaround period and before the beginning of the next monitoring period; and

5) The leak recurrence rate is equal to the leak occurrence rate; sources that experience leak occurrence or leak recurrence immediately leak at the rate of the "leaking sources" category.

A limitation of the LDAR analysis is that the emission data used to evaluate leak detection and repair program effectiveness in reducing fugitive emissions of VOC were collected in the field over a very short period of time in relation to the average operating time between process unit turnarounds: the emission test data represent only several minutes out of an average 2-year operation schedule between process unit turnarounds. Further, all leaks do not occur simultaneously. The quantity of leaking sources in a process unit accumulates over time until a maximum number of sources leaking is achieved prior to maintenance and repair activities at process unit trunaround. Consequently, the fraction of sources found leaking and the leak detection and repair program effectiveness for the population of sources is dependent on the time at which field testing occurred in relation to previous maintenance activities at process unit turnaround. For example, if the field test was performed immediately before process unit turnaround, the degree of emission reduction attributable to the leak detection and repair program would approach the maximum emission reduction attainable. Alternately, if field testing is performed shortly after process unit turnaround, the effectiveness of the leak detection and repair program will be minimal and the actual emission reduction may be underpredicted. The cyclical nature of the number of leaking sources accumulating between process unit turnarounds and the effect this cycle has on predicting emission reductions by leak detection and repair programs are illustrated in Figure F-2.

Generally, there is no indication of where in the repair cycle field testing occurred. Thus, there is some uncertainty in emission reduction estimates associated with leak detection and repair programs. Even though the phase on the repair cycle at which field test data collection occurred is unknown, it is known that the maximum number of leaking sources occurs near the end of each repair cycle. It is probable that for any randomly selected time, the number of sources tested and found leaking will be less than the maximum number and emission reductions will be less than the maximum attainable. Therefore, the LDAR model probably predicts emission reductions that are less than the maximum actually attainable. That is, the LDAR model emission reduction estimates probably are conservative.



Ⓐ LDRP emission reduction affectiveness approaching maximum attainable value if field data collected at this point in the leak repair cycle is used in LDAR model.

Ⓑ LDRP emission reduction effectiveness underpredicted if field data collected at this point in the leak repair cycle is used in LDAR model.

This figure is presented for illustrative purposes only and should not be used to determine the fraction of sources leaking at any particular phase in the leak repair cycle.

Figure F-2. Effect Of Leak Repair Cycles On Field Emission Test Results And Leak Detection And Repair Program (LDRP) Effectiveness.

F.2 LDAR MODEL IMPACTS

The LDAR model is used to determine emission reductions, fraction of sources monitored (screened), and fraction of sources repaired (operated on) for valves and pumps that are subject to leak detection and repair activities. The values determined for fraction of sources screened and fraction of sources operated on then are used to establish monitoring and repair labor requirements. Monthly, monthly/quarterly, quarterly, and annual leak detection and repair program scenarios for valves in gas/vapor service and valves in light liquid service are evaluated. Monthly, quarterly, and annual leak detection and repair program scenarios for pumps in light liquid service also are examined. In addition, safety/relief valve LDAR model impacts are estimated. The LDAR model input and output data used to evaluate these leak detection and repair program scenarios are presented in Tables F-1 through F-6.

F.2.1. Environmental Impacts

The resultant LDAR model outputs are used to generate emission reduction and energy impacts associated with Regulatory Alternatives II through V. These environmental impacts, presented in Tables F-7 through F-11, are analogous to the impact tables presented in Chapter 7. Most bases for calculating the impacts (such as component counts and model unit counts) are unchanged. However, the LDAR model impacts for gas/vapor service valves, light liquid service valves, light liquid service pumps, and gas/vapor service safety/relief valves are substituted for their respective ABCD model impacts.

F.2.2 Cost Impacts

The LDAR model outputs also are used to determine costs corresponding to the leak detection and repair programs required by the regulatory alternatives. The cost impacts, presented in Tables F-12 through F-23, are developed by substituting LDAR model leak detection/repair costs and emission reductions for ABCD model leak detection/repair costs and emission reductions. All other cost bases presented in Chapter 8 (including capital costs) are unchanged.

F.2.3. Economic Impacts

Economic impacts of implementing the regulatory alternatives are determined using the LDAR model cost impacts developed in Tables F-12

TABLE F-1. INPUT DATA FOR EXAMINING THE REDUCTION IN AVERAGE LEAK RATE DUE TO A VALVE MAINTENANCE PROGRAM

TYPE OF SOURCE/UNIT	EI MEAN (95% CI)	FF MEAN(95% CI)	IFL MEAN (SE)	F1 MEAN (SE)	F2 MEAN (SE)	FE1 MEAN (SE)	FE2 MEAN (SE)
VALVES							
MONTHLY UNITS							
GAS	0.027	0.038	0.1	0.374	0.023	0.1	0.14
	(,)	(,)	( )	( )	( )	( )	( )
LIGHT LIQUID	0.011	0.038	0.11	0.374	0.023	0.1	0.14
	(,)	(,)	( )	( )	( )	( )	( )
QUART/MONTH UNITS							
GAS	0.027	0.038	0.1	0.374	0.023	0.1	0.14
	(,)	(,)	( )	( )	( )	( )	( )
LIGHT LIQUID	0.011	0.038	0.11	0.374	0.023	0.1	0.14
	(,)	(,)	( )	( )	( )	( )	( )
QUARTERLY UNITS							
GAS	0.027	0.038	0.1	0.374	0.023	0.1	0.14
	(,)	(,)	( )	( )	( )	( )	( )
LIGHT LIQUID	0.011	0.038	0.11	0.374	0.023	0.1	0.14
	(,)	(,)	( )	( )	( )	( )	( )
YEARLY UNITS							
GAS	0.027	0.038	0.1	0.374	0.023	0.1	0.14
	(,)	(,)	( )	( )	( )	( )	( )
LIGHT LIQUID	0.011	0.038	0.11	0.374	0.023	0.1	0.14
	(,)	(,)	( )	( )	( )	( )	( )

TURNAROUND EVERY 24 MONTHS -- FRACTION OF SOURCES UNREPAIRED (FE1) IS 0 AT THE TURNAROUNDS

EI = EMISSION FACTOR (KG/HR/SOURCE) FOR ALL SOURCES INITIALLY

FF = FRACTION OF NON-LEAKING SOURCES AT THE BEGINNING THAT BECOME LEAKERS (SCREENING VALUE GREATER THAN OR EQUAL TO 10,000 PPMV) DURING A 12 MONTH PERIOD (LEAK OCCURRENCE)

IFL = FRACTION OF SOURCES LEAKING INITIALLY

F1 = ONE MINUS EMISSIONS REDUCTION FROM AN UNSUCCESSFUL REPAIR, DEFINED BY EE=F1*EL WHERE,
EL=AVERAGE EMISSION FACTOR FOR SOURCES LEAKING AT OR ABOVE THE ACTION LEVEL, AND
EE=AVERAGE EMISSION FACTOR FOR SOURCES WHICH EXPERIENCE EARLY LEAK RECURRENCES

F2 = ONE MINUS EMISSIONS REDUCTION FROM A SUCCESSFUL REPAIR, DEFINED BY EP=F2*EL WHERE EL IS AS DEFINED ABOVE, AND
EP=AVERAGE EMISSION FACTOR FOR SOURCES LEAKING BELOW THE ACTION LEVEL

FE1 = FRACTION OF SOURCES THAT ARE LEAKING AND FOR WHICH ATTEMPTS AT REPAIR HAVE FAILED
FE2 = FRACTION OF REPAIRED SOURCES THAT EXPERIENCE EARLY FAILURES

INPUT DATA

Table F-2. FOR EXAMINING THE REDUCTION IN AVERAGE LEAK RATE DUE TO A PUMP MAINTENANCE PROGRAM

```
                             EI               FF             IFL          F1          F2          FE1         FE2
   TYPE OF             -------------    -------------    ---------   ---------   ---------   ---------   ---------
 SOURCE/UNIT           MEAN (95% CI)    MEAN(95% CI)     MEAN (SE)   MEAN (SE)   MEAN (SE)   MEAN (SE)   MEAN (SE)
--------------------------------------------------------------------------------------------------------------------
PUMPS
MONTHLY UNITS
      VOC                  0.113            0.102           0.24         1         0.027        0           0
                       (     ,     )    (     ,     )    (       )   (       )   (       )   (       )   (       )
QUART/MONTH UNITS
      VOC                  0.113            0.102           0.24         1         0.027        0           0
                       (     ,     )    (     ,     )    (       )   (       )   (       )   (       )   (       )
QUARTERLY UNITS
      VOC                  0.113            0.102           0.24         1         0.027        0           0
                       (     ,     )    (     ,     )    (       )   (       )   (       )   (       )   (       )
YEARLY UNITS
      VOC                  0.113            0.102           0.24         1         0.027        0           0
                       (     ,     )    (     ,     )    (       )   (       )   (       )   (       )   (       )
        TURNAROUND EVERY 24 MONTHS -- FRACTION OF SOURCES UNREPAIRED (FE1) IS 0 AT THE TURNAROUNDS
        EI = EMISSION FACTOR (KG/HR/SOURCE) FOR ALL SOURCES INITIALLY
        FF = FRACTION OF NON-LEAKING SOURCES AT THE BEGINNING THAT BECOME LEAKERS
             (SCREENING VALUE GREATER THAN OR EQUAL TO 10,000 PPMV) DURING A 12 MONTH PERIOD (LEAK OCCURRENCE)
        IFL = FRACTION OF SOURCES LEAKING INITIALLY
        F1 = ONE MINUS EMISSIONS REDUCTION FROM AN UNSUCCESSFUL REPAIR, DEFINED BY EE=F1*EL WHERE,
             EL=AVERAGE EMISSION FACTOR FOR SOURCES LEAKING AT OR ABOVE THE ACTION LEVEL, AND
             EE=AVERAGE EMISSION FACTOR FOR SOURCES WHICH EXPERIENCE EARLY LEAK RECURRENCES
        F2 = ONE MINUS EMISSIONS REDUCTION FROM A SUCCESSFUL REPAIR,  DEFINED BY EP=F2*EL WHERE EL IS AS DEFINED ABOVE, AND
             EP=AVERAGE EMISSION FACTOR FOR SOURCES LEAKING BELOW THE ACTION LEVEL
        FE1 = FRACTION OF SOURCES THAT ARE LEAKING AND FOR WHICH ATTEMPTS AT REPAIR HAVE FAILED
        FE2 = FRACTION OF REPAIRED SOURCES THAT EXPERIENCE EARLY FAILURES
```

Table F-3. VALVE EMISSION FACTORS AND MASS EMISSION REDUCTIONS

SUMMARY OF ESTIMATED EMISSION FACTORS (KG/HR) AND FRACTIONAL REDUCTION
IN MASS EMISSIONS FOR VALVES BY TURNAROUND - MONTHLY UNITS

	GAS SERVICE		LIGHT LIQUID SERVICE	
TURNAROUND	MEAN EMISSION-KG/HR	REDUCTION	MEAN EMISSION-KG/HR	REDUCTION
1	0.0088	0.673	0.0034	0.695
2	0.0080	0.703	0.0030	0.725

SUMMARY OF ESTIMATED EMISSION FACTORS (KG/HR) AND FRACTIONAL REDUCTION
IN MASS EMISSIONS FOR VALVES BY TURNAROUND - QUART/MONTH UNITS

	GAS SERVICE		LIGHT LIQUID SERVICE	
TURNAROUND	MEAN EMISSION-KG/HR	REDUCTION	MEAN EMISSION-KG/HR	REDUCTION
1	0.0113	0.583	0.0043	0.611
2	0.0105	0.611	0.0040	0.640

SUMMARY OF ESTIMATED EMISSION FACTORS (KG/HR) AND FRACTIONAL REDUCTION
IN MASS EMISSIONS FOR VALVES BY TURNAROUND - QUARTERLY UNITS

	GAS SERVICE		LIGHT LIQUID SERVICE	
TURNAROUND	MEAN EMISSION-KG/HR	REDUCTION	MEAN EMISSION-KG/HR	REDUCTION
1	0.0116	0.570	0.0044	0.599
2	0.0109	0.597	0.0041	0.627

SUMMARY OF ESTIMATED EMISSION FACTORS (KG/HR) AND FRACTIONAL REDUCTION
IN MASS EMISSIONS FOR VALVES BY TURNAROUND - YEARLY UNITS

	GAS SERVICE		LIGHT LIQUID SERVICE	
TURNAROUND	MEAN EMISSION-KG/HR	REDUCTION	MEAN EMISSION-KG/HR	REDUCTION
1	0.0231	0.143	0.0088	0.204
2	0.0230	0.149	0.0087	0.212

Table F- 4. FRACTION OF VALVES SCREENED AND OPERATED ON

SUMMARY OF TOTAL FRACTION OF SOURCES SCREENED AND OPERATED ON FOR VALVES BY YEAR
MONTHLY UNITS

YEAR	GAS SERVICE		LIGHT LIQUID SERVICE	
	TOTAL FRACTION OF SOURCES SCREENED	TOTAL FRACTION OF SOURCES OPERATED ON	TOTAL FRACTION OF SOURCES SCREENED	TOTAL FRACTION OF SOURCES OPERATED ON
1	12.7728	0.2825	12.7594	0.2937
2	11.5686	0.2110	11.5553	0.2119
3	11.8974	0.1792	11.8972	0.1793
4	11.6917	0.2026	11.6915	0.2026
5	11.8991	0.1776	11.8991	0.1776

SUMMARY OF TOTAL FRACTION OF SOURCES SCREENED AND OPERATED ON FOR VALVES BY YEAR
QUART/MONTH UNITS

YEAR	GAS SERVICE		LIGHT LIQUID SERVICE	
	TOTAL FRACTION OF SOURCES SCREENED	TOTAL FRACTION OF SOURCES OPERATED ON	TOTAL FRACTION OF SOURCES SCREENED	TOTAL FRACTION OF SOURCES OPERATED ON
1	5.2994	0.2776	5.3121	0.2888
2	4.1169	0.2065	4.1121	0.2074
3	4.3150	0.1771	4.3170	0.1773
4	4.1595	0.1983	4.1594	0.1983
5	4.2971	0.1756	4.2971	0.1756

SUMMARY OF TOTAL FRACTION OF SOURCES SCREENED AND OPERATED ON FOR VALVES BY YEAR
QUARTERLY UNITS

YEAR	GAS SERVICE		LIGHT LIQUID SERVICE	
	TOTAL FRACTION OF SOURCES SCREENED	TOTAL FRACTION OF SOURCES OPERATED ON	TOTAL FRACTION OF SOURCES SCREENED	TOTAL FRACTION OF SOURCES OPERATED ON
1	4.9324	0.2760	4.9281	0.2872
2	3.8648	0.2051	3.8603	0.2060
3	3.9726	0.1762	3.9725	0.1764
4	3.9044	0.1970	3.9043	0.1970
5	3.9730	0.1748	3.9730	0.1748

SUMMARY OF TOTAL FRACTION OF SOURCES SCREENED AND OPERATED ON FOR VALVES BY YEAR
YEARLY UNITS

YEAR	GAS SERVICE		LIGHT LIQUID SERVICE	
	TOTAL FRACTION OF SOURCES SCREENED	TOTAL FRACTION OF SOURCES OPERATED ON	TOTAL FRACTION OF SOURCES SCREENED	TOTAL FRACTION OF SOURCES OPERATED ON
1	1.9900	0.2512	1.9890	0.2622
2	0.9749	0.1798	0.9738	0.1808
3	1.0000	0.1634	1.0000	0.1636
4	0.9837	0.1735	0.9836	0.1736
5	1.0000	0.1627	1.0000	0.1627

Table F- 5. PUMP EMISSION FACTORS AND MASS EMISSION REDUCTIONS

SUMMARY OF ESTIMATED EMISSION FACTORS (KG/HR) AND FRACTIONAL REDUCTION
IN MASS EMISSIONS FOR PUMPS BY TURNAROUND - MONTHLY UNITS

	VOC SERVICE	
TURNAROUND	MEAN EMISSION-KG/HR	REDUCTION
1	0.0189	0.833
2	0.0189	0.833

SUMMARY OF ESTIMATED EMISSION FACTORS (KG/HR) AND FRACTIONAL REDUCTION
IN MASS EMISSIONS FOR PUMPS BY TURNAROUND - QUARTERLY UNITS

	VOC SERVICE	
TURNAROUND	MEAN EMISSION-KG/HR	REDUCTION
1	0.0328	0.709
2	0.0328	0.709

SUMMARY OF ESTIMATED EMISSION FACTORS (KG/HR) AND FRACTIONAL REDUCTION
IN MASS EMISSIONS FOR PUMPS BY TURNAROUND - YEARLY UNITS

	VOC SERVICE	
TURNAROUND	MEAN EMISSION-KG/HR	REDUCTION
1	0.0883	0.218
2	0.0883	0.218

Table F-6. FRACTION OF PUMPS SCREENED AND OPERATED ON

SUMMARY OF TOTAL FRACTION OF SOURCES SCREENED AND OPERATED ON FOR PUMPS BY YEAR
MONTHLY UNITS

	VOC SERVICE	
YEAR	TOTAL FRACTION OF SOURCES SCREENED	TOTAL FRACTION OF SOURCES OPERATED ON
1	13.0000	0.6480
2	12.0000	0.4080
3	12.0000	0.4080
4	12.0000	0.4080
5	12.0000	0.4080

SUMMARY OF TOTAL FRACTION OF SOURCES SCREENED AND OPERATED ON FOR PUMPS BY YEAR
QUARTERLY UNITS

	VOC SERVICE	
YEAR	TOTAL FRACTION OF SOURCES SCREENED	TOTAL FRACTION OF SOURCES OPERATED ON
1	5.0000	0.6343
2	4.0000	0.3943
3	4.0000	0.3943
4	4.0000	0.3943
5	4.0000	0.3943

SUMMARY OF TOTAL FRACTION OF SOURCES SCREENED AND OPERATED ON FOR PUMPS BY YEAR
YEARLY UNITS

	VOC SERVICE	
YEAR	TOTAL FRACTION OF SOURCES SCREENED	TOTAL FRACTION OF SOURCES OPERATED ON
1	2.0000	0.5797
2	1.0000	0.3397
3	1.0000	0.3397
4	1.0000	0.3397
5	1.0000	0.3397

Table F-7. CONTROLLED VOC EMISSION FACTORS FOR VARIOUS INSPECTION INTERVALS USING THE LDAR MODEL[a]

Source Type	Inspection Interval	Control Efficiency (percent)	Controlled Emission Factors (kg/day)
Valves			
Gas/vapor	Quarterly[b,c,d]	59.7	0.262
	Monthly[e]	70.3	0.192
Light Liquid	Annual[b]	21.2	0.209
	Quarterly[c,d]	62.7	0.098
	Monthly[e]	72.5	0.072
Pump Seals			
Light Liquid	Annual[b]	21.8	2.12
	Monthly[c]	83.3	0.45
Safety/Relief Valves			
Gas/Vapor	Quarterly[b,f]	44	2.18

[a] Table F-7 presents information based upon the LDAR model which is analogous to ABCD model information presented in Table 7-1.

[b] Required in Regulatory Alternative II.

[c] Required in Regulatory Alternative III.

[d] Required in Regulatory Alternative IV.

[e] Required in Regulatory Alternative V.

[f] Safety/relief valve LDAR model outputs were estimated by weighting the safety/relief valve ABCD model control effectiveness by the ratio of the quarterly inspection for gas/vapor valve ABCD model estimate to the gas/vapor valve LDAR model estimate. Calculated as:

$$\begin{array}{c}\text{Safety/Relief Valve}\\ \text{LDAR Control}\\ \text{Effectiveness}\end{array} \simeq \left(\begin{array}{c}\text{Safety/Relief Valve}\\ \text{ABCD Model}\\ \text{Control Effectiveness}\\ \text{Table 7-1}\end{array}\right) \frac{\left(\begin{array}{c}\text{Valve LDAR Model}\\ \text{Control}\\ \text{Effectiveness Table F-3}\end{array}\right)}{\left(\begin{array}{c}\text{Valve ABCD Model}\\ \text{Control}\\ \text{Effectiveness}\\ \text{Table 7-1}\end{array}\right)}$$

$$(0.64)\ \frac{(0.597)}{(0.86)} = 0.44$$

The estimated LDAR model control emission factor for quarterly leak detection and repair for safety/relief valves is calculated as:

$$\left(\begin{array}{c}\text{Uncontrolled}\\ \text{Safety/Relief Valve}\\ \text{Emission Factor}\\ \text{Table 7-1}\end{array}\right)\left(1-\left[\begin{array}{c}\text{Estimated LDAR}\\ \text{Model Emission}\\ \text{Reduction for}\\ \text{Safety/Relief}\\ \text{Valves}\end{array}\right]\right) = (3.9\ \text{kg/day})(1-0.44)$$

$$= 2.18\ \text{kg/day}$$

Table 8. VOC EMISSIONS FOR REGULATORY ALTERNATIVES BASED ON LDAR MODEL[a]
(Model Unit A)

	Regulatory Alternatives											
	I		II		III		IV		V		VI	
Source type	Uncontrolled emissions[b] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total
Valves												
gas/vapor	83	38	34	26	34	44	34	46	25	43	0	0
light liquid	65	30	52	40	24	31	24	32	18	31	0	0
heavy liquid	0.80	<1	0.80	<1	0.80	1	0.80	1	0.80	1	0.80	5
Open-Ended Lines	3.9	2	0	0	0	0	0	0	0	0	0	0
Sampling connections	3.6	2	3.6	3	0	0	0	0	0	0	0	0
Pump Seals												
light liquid	19	9	15	12	3.2	4	0	0	0	0	0	0
heavy liquid	2.0	1	2.0	2	2.0	3	2.0	3	2.0	3	2.0	13
Flanges	13	6	13	10	13	17	13	18	13	22	13	82
Relief Valves gas/vapor	12	5	6.5	5	0	0	0	0	0	0	0	0
Compressor Seals	15	7	3.2	2	0	0	0	0	0	0	0	0
Total	217		130		77		74		59		16	

[a] Table F-8 is analogous to Table 7-2 which is based on the ABCD model.

[b] Uncontrolled emissions are obtained by multiplying the uncontrolled emission factors for each source (Table 3-1) by their respective model unit component counts (Table 6-1).

[c] Controlled emissions from gas/vapor valves, light liquid valves, light liquid pumps, and gas vapor safety/relief valves are obtained by multiplying the controlled emission factors for these sources (Table F-7) by their respective model unit component counts (Table 6-1). Other source emission estimates are taken from Table 7-2.

Table 8. VOC EMISSIONS FOR REGULATORY ALTERNATIVES BASED ON LDAR MODEL[a] (Continued)
(Model Unit B)

	Regulatory Alternatives											
	I		II		III		IV		V		VI	
Source type	Uncontrolled emissions[b] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total
Valves												
gas/vapor	170	37	68	26	68	44	68	46	50	42	0	0
light liquid	130	28	100	38	49	32	49	33	36	31	0	0
heavy liquid	2	<1	2	<1	2	1	2	1	2	2	2	6
Open-Ended Lines	7	2	0	0	0	0	0	0	0	0	0	0
Sampling connections	7.2	2	7.2	3	0	0	0	0	0	0	0	0
Pump Seals												
light liquid	38	8	30	12	6.3	4	0	0	0	0	0	0
heavy liquid	3	<1	3	1	3	2	3	2	3	2	3	9
Flanges	27	6	27	10	27	17	27	18	27	23	27	85
Relief Valves gas/vapor	27	6	15	6	0	0	0	0	0	0	0	0
Compressor Seals	45	10	9.6	4	0	0	0	0	0	0	0	0
Total	456		262		155		149		118		32	

[a] Table F-8 is analogous to Table 7-2 which is based on the ABCD model.

[b] Uncontrolled emissions are obtained by multiplying the uncontrolled emission factors for each source (Table 3-1) by their respective model unit component counts (Table 6-1).

[c] Controlled emissions from gas/vapor valves, light liquid valves, light liquid pumps, and gas vapor safety/relief valves are obtained by multiplying the controlled emission factors for these sources (Table F-7) by their respective model unit component counts (Table 6-1). Other source emission estimates are taken from Table 7-2.

Table 8. VOC EMISSIONS FOR REGULATORY ALTERNATIVES BASED ON LDAR MODEL[a] (Concluded)
(Model Unit C)

	Regulatory Alternatives											
	I		II		III		IV		V		VI	
Source type	Uncontrolled emissions[b] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total	Controlled emissions[c] (kg/day)	Percent of total
Valves												
gas/vapor	500	38	200	26	200	43	200	45	150	43	0	0
light liquid	390	29	310	40	150	33	150	34	110	31	0	0
heavy liquid	4	>1	4	1	4	1	4	1	4	1	4	4
Open-Ended Lines	20	2	0	0	0	0	0	0	0	0	0	0
Sampling connections	22	2	22	3	0	0	0	0	0	0	0	0
Pump Seals												
light liquid	110	8	85	11	18	4	0	0	0	0	0	0
heavy liquid	10	>1	10	1	10	2	10	2	10	3	10	11
Flanges	77	6	77	10	77	17	77	18	77	22	77	85
Relief Valves gas/vapor	78	6	44	6	0	0	0	0	0	0	0	0
Compressor Seals	120	9	26	3	0	0	0	0	0	0	0	0
Total	1331		778		459		441		351		91	

[a] Table F-8 is analogous to Table 7-2 which is based on the ABCD model.

[b] Uncontrolled emissions are obtained by multiplying the uncontrolled emission factors for each source (Table 3-1) by their respective model unit component counts (Table 6-1).

[c] Controlled emissions from gas/vapor valves, light liquid valves, light liquid pumps, and gas vapor safety/relief valves are obtained by multiplying the controlled emission factors for these sources (Table F-7) by their respective model unit component counts (Table 6-1). Other source emission estimates are taken from Table 7-2.

Table F-9. ANNUAL MODEL UNIT EMISSIONS AND AVERAGE PERCENT EMISSION REDUCTION FROM REGULATORY ALTERNATIVE I BASED ON LDAR MODEL RESULTS[a]

Regulatory Alternative	Model unit emissions (Mg/year)[b]			Average percent emission reduction	
	A	B	C	From Regulatory Alternative I	Incremental
I[c]	79	166	486	--	--
II	47	95	284	42	42
III	28	57	167	65	41
IV	27	55	161	67	4
V	22	43	128	74	20
VI	6	12	33	93	73

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[a] Table F-9 is analogous to Table 7-3 which is based on the ABCD model.

[b] From Table F-8. Based on 365 days per year.

[c] Regulatory Alternative I represents "uncontrolled" emissions.

Table 10. PROJECTED VOC FUGITIVE EMISSIONS FROM AFFECTED MODEL UNITS FOR REGULATORY ALTERNATIVES FOR 1982-1986 BASED ON LDAR MODEL RESULTS[a]

		Model Units[b]			Total Fugitive Emissions Projected under Regulatory Alternative (Gg/yr)[c]						
	Year	A	B	C	I	Baseline[d]	II	III	IV	V	VI
New Units	1982	9	5	4	3.5	2.7	2.0	1.2	1.1	0.9	0.2
	1983	19	10	9	7.5	5.8	4.4	2.6	2.5	2.0	0.5
	1984	29	15	14	11.6	8.8	6.7	4.1	3.8	3.1	0.8
	1985	39	21	19	15.8	12.0	9.1	5.5	5.2	4.2	1.1
	1986	49	27	24	20.0	15.3	11.6	7.0	6.6	5.4	1.4
Modified/ Reconstructed Units	1982	9	15	11	8.5	6.5	4.9	3.0	2.8	2.3	0.6
	1983	18	31	22	17.3	13.2	10.0	6.0	5.7	4.6	1.2
	1984	27	47	33	26.0	19.8	15.0	9.1	8.6	7.0	1.8
	1985	37	67	44	35.4	27.0	20.4	12.4	11.7	9.5	2.5
	1986	47	79	56	44.0	33.6	25.4	15.4	14.6	11.8	3.1

[a] Table F-10 is analogous to Table 7-4 which is based on the ABCD model.

[b] The numbers of affected model units projected through 1986 are cumulative and distinguished between new unit construction and modification/reconstruction. Units in existence prior to 1982 are otherwise excluded. A discussion of the growth projections is in Appendix E.

[c] The total fugitive emissions from Model Units A, B, and C are derived from the emissions per model unit in Table F-9. The sum of emissions in any one year is the sum of the products of the number of affected facilities per model unit times the emissions per model unit.

[d] The baseline emissions level is the weighted sum of the emissions in Regulatory Alternative I (uncontrolled) and II (CTG Controls) and is based on the proportion of refineries in nonattainment (169/302 = 56 percent) and attainment (133/302 = 44 percent) areas. Reference 4.

TABLE F-11. PROJECTED ENERGY IMPACTS OF REGULATORY ALTERNATIVES FOR 1982-1986 BASED ON LDAR MODEL RESULTS

	Regulatory Alternative	Five-year total reduction from baseline (Gg)[a]	Energy value of emission reduction (terajoules)[b]	Crude oil equivalent of emission reduction ($10^3 m^3$)[c]
New Units	II	10.8	529	14
	III	24.2	1,190	31
	IV	25.4	1,240	32
	V	29.0	1,420	37
	VI	40.6	1,990	52
Modified/ Reconstructed Units	II	24.4	1,200	31
	III	54.2	2,660	69
	IV	56.7	2,780	72
	V	64.9	3,180	82
	VI	90.9	4,450	116

[a] Estimated total fugitive VOC emission reduction from Model Units A, B, and C, from Table F-10.

[b] Based on 49 TJ/Gg, these values represent energy credits. Reference 5.

[c] Based on 38.5 TJ/Mm^3 (6.12×10^9 J/bbl) crude oil. Reference 6.

Table F-12. MONITORING AND MAINTENANCE LABOR-HOUR REQUIREMENTS BASED ON LDAR MODEL RESULTS[a]

				LEAK DETECTION					LEAK REPAIR			
	Components Per Model Unit					Monitoring Labor-Hours Required[c,d]				Maintenance Labor-Hours[f]		
Source Type	A	B	C	Type of Monitoring[b]	Fraction of Sources Screened	A	B	C	Fraction of Sources Operated on[e]	A	B	C
Valves												
Gas/Vapor	130	260	780	Instrument	$3.94^{h,i,j}$	17	34	102	0.186	27	55	164
				Instrument	11.80^{k}	51	102	307	0.190	28	56	167
light liquid	250	500	1500	Instrument	0.99^{h}	8.3	17	50	0.168	47	95	285
				Instrument	$3.94^{i,j}$	33	66	197	0.186	52	105	315
				Instrument	11.80^{k}	98	197	590	0.190	54	107	322
Pump Seals												
light liquid	7	14	40	Instrument	1^{h}	1.2	2.3	6.7	0.340	190	381	1,088
				Instrument	12^{i}	14	28	80	0.394	221	441	1,261
				Visual	$52^{h,i,j,k,l}$	3	6.1	17				
Relief Valves												
Gas/Vapor	3	7	20	Instrument	3.94^{h}	3.2	7.4	21.0	0.186	0	0	0
Compressor Seals												
Gas/Vapor	1	3	8	Instrument	^{h}	1	2	5.3	0.14^{g}	6	17	45

[a] Table F-12 is analogous to the ABCD analysis presented in Table 8-3.

[b] Assumes that instrument monitoring requires a two-person team and visual monitoring one person.

[c] From Table F-4 and F-6.

[d] Monitoring time per person: valves 1 min., pumps-instrument 5 min., visual 1/2 min.; compressors 5 min.; and safety/relief valves 8 min. Monitoring labor-hours = number of workers x number of components x time to monitor x fraction of sources screened.

[e] From Table F-4 and F-6

[f] Maintenance labor-hours = number of components x repair time x fraction of sources operated on. Labor-hours: Repair time per component: pumps - 80 hrs., compressors - 40 hrs., valves - 1.13 hrs. (Basis: weighted average on 75 percent of the leaks repaired on-line requiring 10 minutes per repair, and on 25 percent of the leaks repaired off-line requiring 4 hrs. per repair. safety relief valves - 0 hrs. (It is assumed that these leaks are corrected by routine maintenance at no additional labor requirement). (.4)(.35) = 0.14.

[g] From Table 8-3. (Fraction of Compressors operated on = quarterly percent recurrence) (Percent of sources leaking) = (0.4)(0.35) = 0.14.

[h] Required in Regulatory Alternative II.

[i] Required in Regulatory Alternative III.

[j] Required in Regulatory Alternative IV.

[k] Required in Regulatory Alternative V.

[l] Required in Regulatory Alternative VI.

Table F-13. LEAK DETECTION AND REPAIR COSTS BASED ON LDAR MODEL RESULTS[a,b] (May 1980 Dollars)

Regulatory Alternatives[c]	Leak Detection Cost Model Units			Repair Cost Model Units		
	A	B	C	A	B	C
II	610	1,240	3,640	4,860	9,860	28,500
III	1,210	2,410	7,130	5,400	10,800	31,300
IV	950	1,910	5,690	1,420	2,880	8,620
V	2,740	5,490	16,500	1,480	2,930	8,800

[a] Table F-13 is analogous to Table 8-4.

[b] Cost = Hours (From Table F-3) x $18.00 per hour.

[c] Regulatory Alternative I has zero costs. Regulatory Alternative VI has negligible costs incurred by weekly visual inspection.

Table 14. RECOVERY CREDITS[a]

Regulatory Alternative	Model Unit A			Model Unit B			Model Unit C		
	VOC Emissions Mg/yr	Emission Reduction from Regulatory Alternative I Mg/yr	Recovered[b] Product Value $/yr	VOC Emissions Mg/yr	Emission Reduction from Regulatory Alternative I Mg/yr	Recovered[b] Product Value $/yr	VOC Emissions Mg/yr	Emission Reduction from Regulatory Alternative I Mg/yr	Recovered[b] Product Value $/yr
I	79	--	--	166	--	--	486	--	--
II	47	32	6,900	95	71	15,300	284	202	43,400
III	28	51	11,000	57	109	23,400	167	319	68,600
IV	27	52	11,200	55	111	23,900	161	325	69,900
V	22	57	12,300	43	123	26,400	128	358	77,000
VI	6	73	15,700	12	154	33,100	33	453	97,400

[a] Table F-14 is analogous to Table 8-8.

[b] This value is obtained by multiplying the recovery credit in Mg per year (Table F-16) by $215 per Mg (May 1980 value of 60:40 LPG to Gasoline Price Ratio). References 7, 8.

Table F-15. ANNUALIZED CONTROL COST ESTIMATES FOR NEW FACILITIES FOR MODEL UNIT A BASED ON THE LDAR MODEL[a]

(Thousands of May 1980 Dollars)

Cost Item	Regulatory Alternatives				
	II	III	IV	V	VI
Annualized Capital Costs[b]					
A. Control Equipment					
1. Monitoring Instrument	2.1	2.1	2.1	2.1	2.1
2. Caps for Open-Ended Lines	0.60	0.60	0.60	0.60	0.60
3. Dual Mechanical Seals					
o Seals			3.9	3.9	3.9
o Installation			0.33	0.33	0.33
4. Barrier Fluid System for Dual Mechanical Seals			2.1	2.1	2.1
5. Pump Seal Barrier Fluid Degassing Reservoir			4.6	4.6	4.6
6. Compressor Degassing Reservoir Vents		1.3	1.3	1.3	1.3
7. Rupture Disk System					
o Disks		0.40	0.40	0.40	0.40
o Assembly and Installation		1.4	1.4	1.4	1.4
8. Closed-Loop Sampling Connections		0.86	0.86	0.86	0.86
9. Sealed Bellows Valves					169
B. Initial Leak Repair	1.0	0.84	0.18	0.18	
Operating Costs					
A. Maintenance Charges					
1. Monitoring Instrument	3.0	3.0	3.0	3.0	3.0
2. Caps for Open-Ended Lines	0.19	0.19	0.19	0.19	0.19
3. Dual Mechanical Seals			0.44	0.44	0.44
4. Barrier Fluid System for Dual Mechanical Seals			0.65	0.65	0.65
5. Pump Seal Barrier Fluid Degassing Reservoir Vents			1.4	1.4	1.4
6. Compressor Degassing Reservoir Vents		0.40	0.40	0.40	0.40
7. Rupture Disk Systems		0.46	0.46	0.46	0.46
8. Closed-Loop Sampling Connections		0.27	0.27	0.27	0.27
9. Sealed Bellows Valves					52
B. Miscellaneous Charges (taxes, insurance, administration)					
1. Monitoring Instrument	0.37	0.37	0.37	0.37	0.37
2. Caps for Open-Ended Lines	0.15	0.15	0.15	0.15	0.15
3. Dual Mechanical Seals			0.35	0.35	0.35
4. Barrier Fluid System for Dual Mechanical Seals			0.52	0.52	0.52
5. Pump Seal Barrier Fluid Degassing Reservoir			1.1	1.1	1.1
6. Compressor Degassing Reservoir Vents		0.32	0.32	0.32	0.32
7. Rupture Disk System		0.37	0.37	0.37	0.37
8. Closed-Loop Sampling Connections		0.21	0.21	0.21	0.21
9. Sealed Bellows Valves					42
C. Labor Charges[c]					
1. Monitoring Labor	0.61	1.2	0.95	2.7	0.055
2. Leak Repair Labor	4.9	5.4	1.4	1.5	0.0
3. Administrative and Support	2.2	2.6	0.94	1.7	0.022
Total Before Credit	15	22	31	34	291
Recovery Credits	(6.9)	(11)	(11)	(12)	(16)
Net Annualized Cost	8.1	11	20	22	275

[a] Values presented in this table are analagous to the ABCD model values presented in Table 8-9.

[b] From Tables 6-1 and 8-1.

[c] From Table F-13.

Table F-16. ANNUALIZED CONTROL COST ESTIMATES FOR NEW FACILITIES FOR MODEL UNIT B BASED ON THE LDAR MODEL[a]

(Thousands of May 1980 Dollars)

Cost Item	Regulatory Alternatives				
	II	III	IV	V	VI
Annualized Capital Cost[b]					
A. Control Equipment					
1. Monitoring Instrument	2.1	2.1	2.1	2.1	2.1
2. Caps for Open-Ended Lines	1.2	1.2	1.2	1.2	1.2
3. Dual Mechanical Seals					
o Seals					
o Installation			7.9	7.9	7.9
4. Barrier Fluid System for Dual Mechanical Seals			0.65	0.65	0.65
5. Pump Seal Barrier Fluid Degassing Reservoir			4.2	4.2	4.2
6. Compressor Degassing Reservoir Vents			9.1	9.1	9.1
7. Rupture Disk System		3.9	3.9	3.9	3.9
o Disks					
o Assembly and Installation		0.93	0.93	0.93	0.93
8. Closed-Loop Sampling Connections		3.3	3.3	3.3	3.3
9. Sealed Bellows Valves		1.7	1.7	1.7	1.7
B. Initial Leak Repair	1.5	1.4	.25	.25	338
Operating Costs					
A. Maintenance Charges					
1. Monitoring Instrument	3.0	3.0	3.0	3.0	3.0
2. Caps for Open-Ended Lines	0.37	0.37	0.37	0.37	0.37
3. Dual Mechanical Seals			0.88	0.88	0.88
4. Barrier Fluid System for Dual Mechanical Seals					
5. Pump Seal Barrier Fluid Degassing Reservoir Vents			1.3	1.3	1.3
6. Compressor Degassing Reservoir Vents			2.8	2.8	2.8
7. Rupture Disk Systems		1.2	1.2	1.2	1.2
8. Closed-Loop Sampling Connections		1.1	1.1	1.1	1.1
9. Sealed Bellows Valves		0.53	0.53	0.53	0.53
B. Miscellaneous Charges (taxes, insurance, administration)					100
1. Monitoring Instrument	0.37	0.37	0.37	0.37	0.37
2. Caps for Open-Ended Lines	0.30	0.30	0.30	0.30	0.30
3. Dual Mechanical Seals			0.70	0.70	0.70
4. Barrier Fluid System for Dual Mechanical Seals					
5. Pump Seal Barrier Fluid Degassing Reservoir Vents			1.0	1.0	1.0
6. Compressor Degassing Reservoir Vents			2.2	2.2	2.2
7. Rupture Disk System		0.96	0.96	0.96	0.96
8. Closed-Loop Sampling Connections		0.86	0.86	0.86	0.86
9. Sealed Bellows Valves		0.42	0.42	0.42	0.42
C. Labor Charges[c]					83
1. Monitoring Labor	1.2	2.4	1.9	5.5	0.11
2. Leak Repair Labor	9.9	10.8	2.9	2.9	0.0
3. Administrative and Support	4.4	5.3	1.9	3.4	0.04
Total Before Credit	24	42	60	65	570
Recovery Credits	(15)	(23)	(24)	(26)	(33)
Net Annualized Cost	9	19	36	39	537

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[a] Values presented in this table are analagous to the ABCD model values presented in Table 8-10.

[b] From Tables 6-1 and 8-1.

[c] From Table F-13.

Table F-17. ANNUALIZED CONTROL COST ESTIMATES FOR NEW FACILITIES FOR MODEL UNIT C BASED ON THE LDAR MODEL[a]

(Thousands of May 1980 Dollars)

Cost Item	Regulatory Alternatives				
	II	III	IV	V	VI
Annualized Capital Costs[b]					
A. Control Equipment					
1. Monitoring Instrument	2.1	2.1	2.1	2.1	2.1
2. Caps for Open-Ended Lines	3.6	3.6	3.6	3.6	3.6
3. Dual Mechanical Seals					
o Seals			23	23	23
o Installation			1.9	1.9	1.9
4. Barrier Fluid System for Dual Mechanical Seals			12	12	12
5. Pump Seal Barrier Fluid Degassing Reservoir			26	26	26
6. Compressor Degassing Reservoir Vents		10	10	10	10
7. Rupture Disk System					
o Disks		2.7	2.7	2.7	2.7
o Assembly and Installation		9.1	9.1	9.1	9.1
8. Closed-Loop Sampling Connections		5.2	5.2	5.2	5.2
9. Sealed Bellows Valves					1,000
B. Initial Leak Repair	4.8	4.3	1.1	1.1	
Operating Costs					
A. Maintenance Charges					
1. Monitoring Instrument	3.0	3.0	3.0	3.0	3.0
2. Caps for Open-Ended Lines	1.1	1.1	1.1	1.1	1.1
3. Dual Mechanical Seals			2.5	2.5	2.5
4. Barrier Fluid System for Dual Mechanical Seals			3.7	3.7	3.7
5. Pump Seal Barrier Fluid Degassing Reservoir Vents			8.0	8.0	8.0
6. Compressor Degassing Reservoir Vents		3.2	3.2	3.2	3.2
7. Rupture Disk Systems		3.0	3.0	3.0	3.0
8. Closed-Loop Sampling Connections		1.6	1.6	1.6	1.6
9. Sealed Bellows Valves					310
B. Miscellaneous Charges (taxes, insurance, administration)					
1. Monitoring Instrument	0.37	0.37	0.37	0.37	0.37
2. Caps for Open-Ended Lines	0.89	0.89	0.89	0.89	0.89
3. Dual Mechanical Seals			2.0	2.0	2.0
4. Barrier Fluid System for Dual Mechanical Seals			2.9	2.9	2.9
5. Pump Seal Barrier Fluid Degassing Reservoir Vents			6.4	6.4	6.4
6. Compressor Degassing Reservoir Vents		2.6	2.6	2.6	2.6
7. Rupture Disk System		2.4	2.4	2.4	2.4
8. Closed-Loop Sampling Connections		1.3	1.3	1.3	1.3
9. Sealed Bellows Valves					250
C. Labor Charges[c]					
1. Monitoring Labor	3.6	7.1	5.7	16.5	0.31
2. Leak Repair Labor	28.5	31.3	8.6	8.8	0.0
3. Administrative and Support	12.8	15.4	5.7	10.1	0.12
Total Before Credit	61	110	161	177	1,700
Recovery Credits	(43)	(69)	(70)	(77)	(97)
Net Annualized Cost	18	41	91	100	1,600

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[a] Values presented in this table are analagous to the ABCD model values presented in Table 8-11.

[b] From Tables 6-1 and 8-1.

[c] From Table F-13.

Table F-18. COST EFFECTIVENESS FOR MODEL UNITS FOR NEW FACILITIES BASED ON THE LDAR MODEL*

(May 1980 Dollars)

	Regulatory Alternative				
	II	III	IV	V	VI
Model Unit A					
Total Capital Cost ($1,000)	13	35	85	85	1,100
Total Annualized Cost ($1,000)	15	22	31	34	291
Net Annualized Cost ($1,000)	8.1	11	20	22	275
Total VOC Reduction (Mg/yr)	32	51	52	57	73
Cost Effectiveness ($/Mg VOC)	250	220	380	390	3,800
Model Unit B					
Total Capital Cost ($1,000)	17	73	168	168	2,300
Total Annualized Cost ($1,000)	24	42	60	65	570
Net Annualized Cost ($1,000)	9	19	36	39	537
Total VOC Reduction (Mg/yr)	71	109	111	123	154
Cost Effectiveness ($/Mg VOC)	130	170	320	320	3,500
Model Unit C					
Total Capital Cost ($1,000)	31	190	470	470	6,600
Total Annualized Cost ($1,000)	61	110	161	177	1,700
Net Annualized Cost ($1,000)	18	41	91	100	1,600
Total VOC Reduction (Mg/yr)	202	319	325	358	453
Cost Effectiveness ($/Mg VOC)	89	130	280	280	3,500

*Values presented in this table are analagous to the ABCD model values presented in Table 8-12.

Table F-19. ANNUALIZED CONTROL COST ESTIMATES FOR MODIFIED/RECONSTRUCTED FACILITIES FOR MODEL UNIT A BASED ON THE LDAR MODEL[a]

(Thousands of May 1980 Dollars)

Cost Item	Regulatory Alternatives[b]			
	III	IV	V	VI
Annualized Capital Costs[c]				
A. Control Equipment				
1. Monitoring Instrument	2.1	2.1	2.1	2.1
2. Caps for Open-Ended Lines	0.60	0.60	0.60	0.60
3. Dual Mechanical Seals				
o Seals		5.1	5.1	5.1
o Installation		0.39	0.39	0.39
4. Barrier Fluid System for Dual Mechanical Seals		2.1	2.1	2.1
5. Pump Seal Barrier Fluid Degassing Reservoir		4.6	4.6	4.6
6. Compressor Degassing Reservoir Vents	1.3	1.3	1.3	1.3
7. Rupture Disk System				
o Disks	0.4	0.4	0.4	0.4
o Assembly and Installation	2.0	2.0	2.0	2.0
8. Closed-Loop Sampling Connections	0.86	0.86	0.86	0.86
9. Sealed Bellows Valves				169
B. Initial Leak Repair	0.84	0.18	0.18	
Operating Costs				
A. Maintenance Charges				
1. Monitoring Instrument	3.0	3.0	3.0	3.0
2. Caps for Open-Ended Lines	0.19	0.19	0.19	0.19
3. Dual Mechanical Seals		0.56	0.56	0.56
4. Barrier Fluid System for Dual Mechanical Seals		0.65	0.65	0.65
5. Pump Seal Barrier Fluid Degassing Reservoir Vents		1.4	1.4	1.4
6. Compressor Degassing Reservoir Vents	0.40	0.40	0.40	0.40
7. Rupture Disk Systems	0.64	0.64	0.64	0.64
8. Closed-Loop Sampling Connections	0.27	0.27	0.27	0.27
9. Sealed Bellows Valves				52
B. Miscellaneous Charges (taxes, insurance, administration)				
1. Monitoring Instrument	0.37	0.37	0.37	0.37
2. Caps for Open-Ended Lines	0.15	0.15	0.15	0.15
3. Dual Mechanical Seals		0.44	0.44	0.44
4. Barrier Fluid System for Dual Mechanical Seals		0.52	0.52	0.52
5. Pump Seal Barrier Fluid Degassing Reservoir		1.1	1.1	1.1
6. Compressor Degassing Reservoir Vents	0.32	0.32	0.32	0.32
7. Rupture Disk System	0.51	0.51	0.51	0.51
8. Closed-Loop Sampling Connections	0.21	0.21	0.21	0.21
9. Sealed Bellows Valves				42
C. Labor Charges[d]				
1. Monitoring Labor	1.2	0.95	2.7	0.055
2. Leak Repair Labor	5.4	1.4	1.5	0.0
3. Administrative and Support	2.6	0.94	1.7	0.022
Total Before Credit	23	34	36	300
Recovery Credits	(11)	(11)	(12)	(16)
Net Annualized Cost	12	23	24	284
Total VOC Reduction (Mg/yr)	51	52	57	73
Cost Effectiveness ($/Mg)	240	440	420	3,900

[a] Values presented in this table are analagous to the ABCD model values presented in Table 8-14.

[b] For Regulatory Alternatives I and II the annualized costs for modified/reconstructed facilities are the same as for new units (Table F-12).

[c] From Tables 6-1 and 8-1.

[d] From Table F-13.

Table F-20. ANNUALIZED CONTROL COST ESTIMATES FOR MODIFIED/RECONSTRUCTED FACILITIES FOR MODEL UNIT B BASED ON THE LDAR MODEL[a] (Thousands of May 1980 Dollars)

Cost Item	Regulatory Alternatives[b]			
	III	IV	V	VI
Annualized Capital Costs[c]				
A. Control Equipment				
1. Monitoring Instrument	2.1	2.1	2.1	2.1
2. Caps for Open-Ended Lines	1.2	1.2	1.2	1.2
3. Dual Mechanical Seals				
o Seals		10	10	10
o Installation		0.78	0.78	0.78
4. Barrier Fluid System for Dual Mechanical Seals		4.2	4.2	4.2
5. Pump Seal Barrier Fluid Degassing Reservoir		9.1	9.1	9.1
6. Compressor Degassing Reservoir Vents	3.9	3.9	3.9	3.9
7. Rupture Disk System				
o Disks	0.9	0.9	0.9	0.9
o Assembly and Installation	4.6	4.6	4.6	4.6
8. Closed-Loop Sampling Connections	1.7	1.7	1.7	1.7
9. Sealed Bellows Valves				338
B. Initial Leak Repair	1.4	0.25	0.25	
Operating Costs				
A. Maintenance Charges				
1. Monitoring Instrument	3.0	3.0	3.0	3.0
2. Caps for Open-Ended Lines	0.37	0.37	0.37	0.37
3. Dual Mechanical Seals		1.1	1.1	1.1
4. Barrier Fluid System for Dual Mechanical Seals		1.3	1.3	1.3
5. Pump Seal Barrier Fluid Degassing Reservoir Vents		2.8	2.8	2.8
6. Compressor Degassing Reservoir Vents	1.2	1.2	1.2	1.2
7. Rupture Disk Systems	1.5	1.5	1.5	1.5
8. Closed-Loop Sampling Connections	0.53	0.53	0.53	0.53
9. Sealed Bellows Valves				100
B. Miscellaneous Charges (taxes, insurance, administration)				
1. Monitoring Instrument	0.37	0.37	0.37	0.37
2. Caps for Open-Ended Lines	0.30	0.30	0.30	0.30
3. Dual Mechanical Seals		0.91	0.91	0.91
4. Barrier Fluid System for Dual Mechanical Seals		1.0	1.0	1.0
5. Pump Seal Barrier Fluid Degassing Reservoir Vents		2.2	2.2	2.2
6. Compressor Degassing Reservoir Vents	0.96	0.96	0.96	0.96
7. Rupture Disk System	1.2	1.2	1.2	1.2
8. Closed-Loop Sampling Connections	0.45	0.45	0.45	0.45
9. Sealed Bellows Valves				83
C. Labor Charges[d]				
1. Monitoring Labor	2.4	1.9	5.5	0.11
2. Leak Repair Labor	10.8	2.9	2.9	0.0
3. Administrative and Support	5.3	1.9	3.3	0.04
Total Before Credit	44	65	70	580
Recovery Credits	(23)	(24)	(26)	(33)
Net Annualized Cost	21	40	43	546
Total VOC Reduction (Mg/yr)	109	111	123	154
Cost Effectiveness ($/Mg)	190	360	350	3,500

[a] Values presented in this table are analagous to the ABCD model values presented in Table 8-15.

[b] For Regulatory Alternatives I and II the annualized costs for modified/reconstructed facilities are the same as for new units (Table F-13).

[c] From Tables 6-1 and 8-1.

[d] From Tables F-13.

Table F-21. ANNUALIZED CONTROL COST ESTIMATES FOR MODIFIED/RECONSTRUCTED FACILITIES FOR MODEL UNIT C BASED ON THE LDAR MODEL[a] (Thousands of May 1980 Dollars)

Cost Item	Regulatory Alternatives[b] III	IV	V	VI
Annualized Capital Costs[c]				
A. Control Equipment				
1. Monitoring Instrument	2.1	2.1	2.1	2.1
2. Caps for Open-Ended Lines	3.6	3.6	3.6	3.6
3. Dual Mechanical Seals				
o Seals		29	29	29
o Installation		2.3	2.3	2.3
4. Barrier Fluid System for Dual Mechanical Seals		12.0	12.0	12.0
5. Pump Seal Barrier Fluid Degassing Reservoir		26	26	26
6. Compressor Degassing Reservoir Vents	10	10	10	10
7. Rupture Disk System				
o Disks	2.7	2.7	2.7	2.7
o Assembly and Installation	13	13	13	13
8. Closed-Loop Sampling Connections	5.2	5.2	5.2	5.2
9. Sealed Bellows Valves				1,000
B. Initial Leak Repair	4.3	1.1	1.1	
Operating Costs				
A. Maintenance Charges				
1. Monitoring Instrument	3.0	3.0	3.0	3.0
2. Caps for Open-Ended Lines	1.1	1.1	1.1	1.1
3. Dual Mechanical Seals		3.2	3.2	3.2
4. Barrier Fluid System for Dual Mechanical Seals		3.7	3.7	3.7
5. Pump Seal Barrier Fluid Degassing Reservoir Vents		8.0	8.0	8.0
6. Compressor Degassing Reservoir Vents	3.2	3.2	3.2	3.2
7. Rupture Disk Systems	4.2	4.2	4.2	4.2
8. Closed-Loop Sampling Connections	1.6	1.6	1.6	1.6
9. Sealed Bellows Valves				310
B. Miscellaneous Charges (taxes, insurance, administration)				
1. Monitoring Instrument	0.37	0.37	0.37	0.37
2. Caps for Open-Ended Lines	0.89	0.89	0.89	0.89
3. Dual Mechanical Seals		2.6	2.6	2.6
4. Barrier Fluid System for Dual Mechanical Seals		2.9	2.9	2.9
5. Pump Seal Barrier Fluid Degassing Reservoir Vents		6.4	6.4	6.4
6. Compressor Degassing Reservoir Vents	2.6	2.6	2.6	2.6
7. Rupture Disk System	3.4	3.4	3.4	3.4
8. Closed-Loop Sampling Connections	1.3	1.3	1.3	1.3
9. Sealed Bellows Valves				250
C. Labor Charges[d]				
1. Monitoring Labor	7.1	5.7	16.5	0.31
2. Leak Repair Labor	31.3	8.6	8.8	0.0
3. Administrative and Support	15.4	5.7	10.1	0.12
Total Before Credit	116	175	191	1,700
Recovery Credits	(69)	(70)	(77)	(97)
Net Annualized Cost	47	105	114	1,600
Total VOC Reduction (Mg/yr)	319	325	358	453
Cost Effectiveness ($Mg)	150	320	320	3,500

[a] Values presented in this table are analagous to the ABCD model values presented in Table 8-16.

[b] For Regulatory Alternatives I and II the annualized costs for modified/reconstructed facilities are the same as for new units (Table F-14).

[c] From Tables 6-1 and 8-1.

[d] From Table F-13.

Table F-22. FIFTH-YEAR NATIONWIDE COSTS OF THE REGULATORY ALTERNATIVES ABOVE REGULATORY ALTERNATIVE I COSTS BASED ON THE LDAR MODEL[a,b]

(Thousands of May 1980 Dollars)

	Regulatory Alternatives				
Cost Item	II	III	IV	V	VI
New Units					
Total Capital Cost[c]	1,800	8,200	20,000	20,000	274,000
Total Annualized Cost[d]	2,800	4,900	7,000	7,700	70,400
Total Recovery Credit[e]	1,800	2,800	2,900	3,200	4,000
Net Annualized Cost	1,000	2,100	4,100	4,500	66,400
Modified/Reconstructed Units					
Total Capital Cost[c]	3,700	19,000	47,000	47,000	610,000
Total Annualized Cost[d]	6,100	11,000	16,500	17,900	155,100
Total Recovery Credit[e]	4,000	6,200	6,300	7,000	8,800
Net Annualized Cost	2,100	4,800	10,200	19,900	146,300

[a] Values presented in this table are analagous to the ABCD model values presented in Table 8-17.

[b] Regulatory Alternative I assumes that no control costs are incurred; therefore, costs for Regulatory Alternatives II through VI are compared to zero.

[c] Total cumulative capital costs in 1986.

[d] Annualized costs for model units subject to each regulatory alternative in the fifth year are calculated by multiplying cost estimates for each model unit under each regulatory alternative by the number of affected model units (from Table 7-4).

[e] From Table F-14.

Table F-23. FIFTH-YEAR NATIONWIDE COSTS FOR
THE PETROLEUM REFINING INDUSTRY ABOVE BASELINE COSTS
BASED ON THE LDAR MODEL[a,b]
(Thousands of May 1980 Dollars)

Cost Item	Regulatory Alternative II	III	IV	V	VI
New Units					
Total Capital Cost[c]	790	7,190	19,000	19,000	273,000
Total Annualized Cost[d]	1,230	3,280	5,380	6,080	68,780
Total Recovery Credit[e]	790	1,790	1,890	2,190	2,990
Net Annualized Cost	440	1,490	3,490	3,890	65,790
Modified/Reconstructed Units					
Total Capital Cost	1,630	16,900	44,900	44,900	607,000
Total Annualized Cost	2,680	7,580	13,080	14,480	151,700
Total Recovery Credit	1,760	3,900	4,060	4,760	6,560
Net Annualized Cost	920	3,680	9,020	9,720	145,140

[a] Values presented in this table are analagous to the ABCD model values presented in Table 8-18.

[b] Baseline costs are calculated from baseline emission levels. As discussed in Chapter 7, the baseline VOC emission level represents a weighted average of emissions from refineries operating in National Ambient Air Quality Standard (NAAQS) for ozone attainment areas (no control) and refineries operating in NAAQS for ozone non-attainment areas (CTG controls). Approximately 44 percent of existing refineries are expected to be operating in ozone attainment areas, and 56 percent are expected to be operating in ozone non-attainment areas.

[c] Total cumulative capital cost above baseline cost in 1986 = total cumulative capital cost in 1986 for each regulatory alternative - total cumulative capital cost in 1986 for baseline (for example, at new units: 0.56 x $1,800 = $1,008).

[d] Total annualized cost above baseline cost = total annualized cost for each regulatory alternative - annualized cost for baseline (for example, at new units: 0.56 x $2,900 = $1,624).

[e] Total recovery credit above baseline credit = total recovery credit for each regulatory alternative - total baseline recovery credit (for example, at new units: 0.56 x $1,800 = $1,008).

through F-23. The price increase under full cost pricing and profit margin decrease under full cost absorption are presented for each model unit and regulatory alternative in Tables F-24 and F-25, respectively. Table F-26 presents a summary of fifth-year net annualized costs above baseline costs based upon the LDAR model analysis.

F.2.4. Comparative Analysis

A comparison of the results of the LDAR model and ABCD models are given in Tables F-27 and F-28. Table F-27 compares the estimated effects of the leak detection and repair scenarios for the individual emission sources. The overall emission and cost impacts determined using the LDAR model values are compared with the ABCD model analysis impacts in Table F-28. The data generated from the LDAR model (Table F-27) have been substituted into the ABCD Model analyses in Chapter 7 and 8 for Model Unit B. The impacts resulting from the control of emission sources other than gas/vapor service valves, and safety/relief valves, light liquid service valves, and light liquid service pumps were kept consistent with ABCD model analysis values reported in Chapters 7 and 8.

This comparison found the LDAR model program emission reductions to be lower than ABCD model (Chapter 7) emission reductions under all leak detection and repair scenarios, except the monthly leak detection and repair scenario for pumps in light liquid service. This comparison also found the LDAR model costs of implementing the leak detection and repair programs to be higher than the ABCD model (Chapter 8) analysis estimates. Higher costs are estimated under the LDAR model due to a higher percentage of valves requiring repair.

The monthly/quarterly leak detection and repair program scenario would require monthly leak detection of all gas/vapor and light liquid service valves. However, valves which do not leak during two consecutive months would then be inspected on a quarterly basis until a leak is detected. Although there is no monthly/quarterly leak detection and repair program in the regulatory alternatives (Chapter 6), the scenario was included to demonstrate the impacts of such a program in relation to straight monthly or quarterly leak detection and repair programs. The LDAR model data output, summarized in Table F-27, indicates that emission reductions under the monthly/quarterly leak detection and

Table F-24. PERCENT INCREASES IN PRICE UNDER FULL COST PRICING BY MODEL UNIT BASED ON LDAR MODEL RESULTS[a]

Unit Type	Regulatory Alternative				
	II	III	IV	V	VI
New Units					
A	0.05	0.08	0.13	0.15	0.85
B	0.02	0.04	0.07	0.08	1.15
C	0.03	0.08	0.16	0.18	2.87
Modified/Reconstructed Units					
A	0.05	0.09	0.15	0.16	1.91
B	0.02	0.05	0.09	0.09	1.17
C	0.03	0.09	0.19	0.21	2.87

[a] Table F-24 is analogous to Table 9-23 which is based on the ABCD model.

Table F-25. PROFIT MARGINS UNDER FULL COST ABSORPTION BY MODEL UNIT BASED ON LDAR MODEL RESULTS[a]

(Baseline Profit Margin = 5.12 Percent)

	Regulatory Alternative				
Unit Type	II	III	IV	V	VI
New Units					
A	5.09	5.07	5.04	5.04	4.12
B	5.11	5.10	5.08	5.08	4.50
C	5.10	5.08	5.03	5.02	3.57
Modified/Reconstructed Units					
A	5.09	5.07	5.03	5.03	4.08
B	5.11	5.10	5.07	5.07	4.49
C	5.10	5.07	5.02	5.01	3.57

[a] Table F-25 is analogous to Table 9-24 which is based on the ABCD model.

Table F-26. SUMMARY OF FIFTH-YEAR NET ANNUALIZED COSTS BASED ON LDAR MODEL RESULTS[a]

(Thousands of May 1980 Dollars)

	Regulatory Alternative				
Unit Type	II	III	IV	V	VI
New Units	440[b]	1,490	3,490	3,890	65,790
Modified/Reconstructed Units	920[b]	3,680	9,020	9,720	145,140
Total	1,360[b]	5,170	12,510	13,610	210,930

[a] Costs are above "baseline" costs as explained in Section 3.3. Table F-26 is analogous to Table 9-25 which presents fifth-year net annualized costs based on the ABCD model.

[b] Values in parentheses denote net annualized credits.

Table F-27. COMPARISON OF RESULTS FROM THE LDAR MODEL WITH THE ABCD MODEL ANALYSIS

Results of ABCD Model Analysis[a]
(LDAR Model Program Output)[b]

Emission Source and LDR Scenario	Emission Factors[c] (kg/day)	Percent Emission Reduction[d]	Total Fraction of Sources Screened In The Second Turnaround-Annual Average[e]	Fraction of Sources Operated on in the Second Turnaround-Annual Average[f]
Gas/Vapor Service Valves				
Quarterly LDR	0.090 (0.262)	86 (60)	4 (3.94)	0.040 (0.186)
Monthly/Quarterly LDR[g]	--- (0.252)	--- (61)	--- (4.23)	--- (0.187)
Monthly LDR	0.058 (0.192)	91 (70)	12 (11.80)	0.060 (0.190)
Light Liquid Service Valves				
Annual LDR	0.091 (0.209)	65 (21)	1 (0.99)	0.022 (0.168)
Quarterly LDR	0.070 (0.098)	73 (63)	4 (3.94)	0.044 (0.186)
Monthly/Quarterly LDR[g]	--- (0.096)	--- (64)	--- (4.23)	--- (0.187)
Monthly LDR	0.060 (0.072)	77 (73)	12 (11.80)	0.066 (0.190)
Light Liquid Service Pumps				
Annual LDR	0.86 (2.12)	68 (22)	1 (1.00)	0.048 (0.340)
Quarterly LDR[h]	--- (0.79)	--- (71)	4 (4.00)	0.096 (0.394)
Monthly LDR	0.54 (0.45)	80 (83)	12 (12.00)	0.144 (0.408)
Gas/Vapor Service Safety/Relief Valves				
Quarterly LDR[i]	1.4 (2.18)	64 (44)	4 --	0.028 --

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[a] The ABCD model analysis leak detection and repair (LDR) program data were obtained from Chapters 6 through 8.

[b] LDAR model values are indicated in parentheses. The LDAR model program data were obtained from Tables F-3 through F-6.

[c] ABCD model emission factor values were obtained from Table 7-1; the LDAR model values were the reported values for the second turnaround in Tables F-3 and F-5. (The emission factors are reported in kg per hour in Tables F-3 and F-5.)

[d] Percent emission reduction values for the ABCD model analysis were calculated from the data in Table 7-2; the corresponding values for the ABCD model were the values for the second turnaround in Tables F-3 and F-5.

[e] Values for total fraction of sources screened were obtained for the ABCD model analysis from Table 8-3. Corresponding values for the LDAR model were the averages of fourth- and fifth-year values reported in Tables F-4 and F-6.

[f] Values for fraction of sources operated on were obtained for the ABCD model analysis from the equation, (initial leak frequency) x (times operated on per year) x (leak recurrence factor); these values are presented in Table 8-3. The corresponding values for the modeled emission program represent the averages of the fourth- and fifth-year values reported in Tables F-4 and F-6.

[g] There is no ABCD model analysis equivalent to the monthly/quarterly LDR scenario for valves.

[h] There is no ABCD model analysis equivalent to the quarterly LDR scenario for pumps.

[i] There is no LDAR model output equivalent to the quarterly LDR scenario. However, the LDAR model output emission factor and emission reduction can be estimated as shown in Table F-7.

Table F-28. COMPARISON OF OVERALL EMISSION AND COST IMPACTS USING LDAR MODEL PROGRAM VALUES WITH ABCD MODEL ANALYSIS IMPACTS

	Regulatory Alternatives			
All Sources	II	III	IV	V
Emissions From Model Unit B				
ABCD Model Emissions[a] (kg/day)	140	98	90	77
LDAR Model Emissions[b] (kg/day)	262[c]	155	149	118
Emissions (kg/day)	122	57	59	41
Annualized Costs For Model Unit B-New Units				
ABCD Model Net Annualized Costs ($1000/yr)[d,e]	(12)[f]	1	28	31
LDAR Model Net Annualized Costs[e,g] ($1000/year)	9	19	36	39
Annualized Costs ($1000/yr)	21	18	8	8

[a] From Table 7-2.

[b] Obtained by substituting LDAR model emissions values and safety/relief for valves in gas/ vapor service, valves in light liquid service, and pumps in light liquid service for ABCD model analysis emission values (Table 7-2). Emission rates for other sources are unchanged.

[c] From Table F-8.

[d] From Table 8-10.

[e] Obtained by substituting LDAR model costs and emission credits for analogous ABCD model costs and emission credits; model unit costs for control of sources other than valves and pumps are the same as in Chapter 8.

[f] Parentheses denote credit.

[g] From Table F-16.

repair program scenario are similar to emission reductions achieved under the straight quarterly leak detection and repair program scenario. The total fraction of sources screened and fraction of sources operated on under the monthly/quarterly leak detection and repair program scenario are also similar to corresponding quarterly leak detection and repair program scenario values.

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*References can be located in Docket Number A-80-44 at the U.S. Environmental Protection Agency Library, Waterside Mall, Washington, D.C.